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Transcript Exhibit(s)

Docket #(s): E-01345 A-16-0036

E-01345 A-16-0123

Arizona Corporation Commission

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Part 8 of 9

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

TOM FORESE- Chairman
BOB BURNS
DOUG LITTLE
ANDY TOBIN
BOYD DUNN

IN THE MATTER OF THE APPLICATION OF
ARIZONA PUBLIC SERVICE COMPANY
FOR A HEARING TO DETERMINE THE
FAIR VALUE OF THE UTILITY PROPERTY
OF THE COMPANY FOR RATEMAKING
PURPOSES, TO FIX A JUST AND
REASONABLE RATE OF RETURN
THEREON, TO APPROVE RATE
SCHEDULES DESIGNED TO DEVELOP
SUCH RETURN.

IN THE MATTER OF FUEL AND
PURCHASED POWER PROCUREMENT
AUDITS FOR ARIZONA PUBLIC SERVICE
COMPANY.

DOCKET NO. E-01345A-16-0036

Arizona Corporation Commission

DOCKETED

MAR 27 2017

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DOCKET NO. E-01345A-16-0123

**STAFF'S NOTICE OF FILING
SETTLEMENT AGREEMENT**

Staff of the Arizona Corporation Commission ("Staff"), hereby files the Proposed Settlement Agreement ("Agreement") in these Dockets on behalf of all of the Signatories.

Appendices F and H are attached to the Agreement. The remaining Appendices will be filed no later than March 31, 2017.

RESPECTFULLY SUBMITTED this 27th day of March 2017.

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On this 27th day of March, 2017, the foregoing document was filed with Docket Control as an Utilities Division Settlement Agreement, and copies of the foregoing were mailed on behalf of the Utilities Division to the following who have not consented to email service. On this date or as soon as possible thereafter, the Commission's eDocket program will automatically email a link to the foregoing to the following who have consented to email service.

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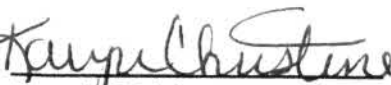
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ARIZONA PUBLIC SERVICE COMPANY
DOCKET NOS. E-01345A-16-0036 and E-01345A-16-0123

SETTLEMENT AGREEMENT

MARCH 27 2017

TABLE OF CONTENTS

I.	RECITALS	5
II.	RATE CASE STABILITY PROVISION	8
III.	RATE INCREASE	8
IV.	BILL IMPACT	8
V.	COST OF CAPITAL	9
VI.	DEPRECIATION/AMORTIZATION AND DECOMMISSIONING	9
VII.	FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS	10
VIII.	TRANSFER OF ITEMS FROM ADJUSTMENT MECHANISMS TO BASE RATES	11
IX.	RATE TREATMENT RELATED TO THE INSTALLATION OF SELECTIVE CATALYTIC REDUCTION EQUIPMENT AT FOUR CORNERS UNITS 4 AND 5	12
X.	COST DEFERRAL RELATED TO THE OCOTILLO MODERNIZATION PROJECT	13
XI.	COST DEFERRAL RELATED TO CHANGES IN ARIZONA PROPERTY TAX RATE	13
XII.	COST OF SERVICE STUDY	14
XIII.	NAVAJO GENERATING STATION	14
XIV.	ANNUAL WORKFORCE PLANNING REPORT	14
XV.	SELF-BUILD MORATORIUM	15
XVI.	TAX EXPENSE ADJUSTOR MECHANISM	16
XVII.	RESIDENTIAL RATE DESIGN	17
XVIII.	RESIDENTIAL RATE DESIGN FOR DISTRIBUTED GENERATION CUSTOMERS	19
XIX.	RESIDENTIAL RATE AVAILABILITY	20

XX.	COMMERCIAL AND INDUSTRIAL RATE DESIGN	21
XXI.	E-32L RATE DESIGN.....	21
XXII.	SCHOOLS DISCOUNT RATE RIDER	21
XXIII.	AG-X	21
XXIV.	MILITARY CUSTOMERS	23
XXV.	REVENUE SPREAD	23
XXVI.	EFFECTIVE DATE OF RATE PLANS AND TRANSITION PLAN.....	24
XXVII.	FIVE MILLION DSMAC ALLOCATION	24
XXVIII.	AZ SUN II	24
XXIX.	LIMITED INCOME PROGRAMS.....	26
XXX.	AMI OPT-OUT/SCHEDULE 1	27
XXXI.	SCHEDULE 3	27
XXXII.	LOST FIXED COST RECOVERY MECHANISM.....	27
XXXIII.	ENVIRONMENTAL IMPROVEMENT SURCHARGE	28
XXXIV.	TRANSMISSION COST ADJUSTMENT MECHANISM	28
XXXV.	CHALLENGES TO DECISION NOS. 75859 AND 75932	28
XXXVI.	POWER SUPPLY ADJUSTOR AUDIT	29
XXXVII.	COMPLIANCE MATTERS	29
XXXVIII.	FORCE MAJEURE PROVISION	29
XXXIX.	COMMISSION EVALUATION OF PROPOSED SETTLEMENT	29
XL.	MISCELLANEOUS PROVISIONS.....	30

**SETTLEMENT AGREEMENT
ARIZONA PUBLIC SERVICE COMPANY'S REQUEST FOR A RATE
INCREASE (DOCKET NO. E-01345-A-0036) AND
THE FUEL AND PURCHASED POWER PROCUREMENT AUDIT OF APS
(DOCKET NO. E-01345A-16-0123)**

The purpose of this Settlement Agreement ("Agreement") is to settle disputed issues related to Arizona Public Service Company's ("APS" or "Company") application to increase its rates (Docket No. E-01345A-16-0036) and the fuel and purchased power procurement audit of APS (Docket No. E-1345A-16-0123). This Agreement is entered into by the following entities:

Arizona Corporation Commission - Utilities Division Staff
Arizona Public Service Company
Residential Utility Consumer Office
Arizona Utility Ratepayer Alliance
Federal Executive Agencies
Arizona Solar Deployment Alliance
Arizona Solar Energy Industries Association
Vote Solar
Solar Energy Industries Association
Arizona School Boards Association and the Arizona Association of School Business Officials
Arizonans for Electric Choice and Competition
Western Resource Advocates
Wal-Mart Stores, Inc. and Sam's West, Inc.
Local Unions 387 and 769 of the International Brotherhood of Electrical Workers, AFL-CIO
Freeport Minerals Corporation
Arizona Community Action Association
The Kroger Co.
Arizona Investment Council
Property Owners & Residents Association, Sun City West
Sun City Home Owners Association
REP America d/b/a ConservAmerica
Constellation New Energy, LLC
Direct Energy Business, LLC
Calpine Energy Solutions, LLC
Arizona Competitive Power Alliance
Energy Freedom Coalition of America
City of Coolidge
Granite Creek Farms, LLC
Granite Creek Power & Gas, LLC

These entities shall be referred to collectively as Signing Parties; a single entity shall be referred to individually as a Signing Party.

I. RECITALS

- 1.1 APS filed the rate application underlying ACC Docket No. E-01345A-16-0036 on June 1, 2016. On August 6, 2016, the administrative law judge granted a motion to consolidate the Fuel and Purchased Power Procurement Audits, ACC Docket No. E-01345A-16-0123, with APS's rate case. Collectively, these dockets may be referred to herein as the Docket.
- 1.2 Subsequently, the Commission approved applications to intervene filed by Richard Gayer; Patricia Ferre; Warren Woodward; Arizona Solar Deployment Alliance ("ASDA"); IO Data Centers, LLC ("IO"); Freeport Minerals Corporation (Freeport) and Arizonans for Electric Choice and Competition (collectively, "AECC"); Sun City Home Owners Association ("Sun City HOA"); Western Resource Advocates ("WRA"); Arizona Investment Council ("AIC"); Arizona Utility Ratepayer Alliance ("AURA"); Property Owners and Residents Association, Sun City West ("PORA"); Arizona Solar Energy Industries Association ("AriSEIA"); Arizona School Boards Association ("ASBA") and Arizona Association of School Business Officials ("AASBO") (collectively, "ASBA/AASBO"); Cynthia Zwick, Arizona Community Action Association ("ACAA"); Southwest Energy Efficiency Project ("SWEEP"); the Residential Utility Consumer Office ("RUCO"); Vote Solar; Electrical District Number Eight and McMullen Valley Water Conservation & Drainage District (collectively, "ED8/McMullen"); The Kroger Co. ("Kroger"); Tucson Electric Power Company ("TEP"); Pima County; Solar Energy Industries Association ("SEIA"); the Energy Freedom Coalition of America ("EFCA"); Wal-Mart Stores, Inc. and Sam's West, Inc. (collectively, "Wal-Mart"); Local Unions 387 and 769 of the International Brotherhood of Electrical Workers, AFL-CIO (collectively, "the IBEW Locals"); Noble Americas Energy Solutions LLC ("Noble Solutions"); the Arizona Competitive Power Alliance ("the Alliance"); Electrical District Number Six, Pinal County, Arizona ("ED 6"); Electrical District Number Seven of the County of Maricopa, State of Arizona ("ED 7"); Aguila Irrigation District ("AID"); Tonopah Irrigation District ("TID"); Harquahala Valley Power District ("HVPD"); and Maricopa County Municipal Water Conservation District Number One ("MWD") (collectively, Districts); SunRun; the Federal Executive Agencies ("FEA"); Constellation New Energy, Inc. ("CNE"); Direct Energy, Inc. ("Direct Energy"); AARP; the City of Coolidge ("Coolidge"); REP America d/b/a ConservAmerica ("ConservAmerica");

and Granite Creek Power & Gas and Granite Creek Farms LLC (collectively, "Granite Creek"). SunRun subsequently withdrew its intervention.

- 1.3 APS filed a notice of revenue requirement settlement discussions on December 29, 2016. Revenue requirement settlement discussions began on January 12, 2017; rate design settlement discussions began on February 6, 2017. The settlement discussions were open, transparent, and inclusive of all parties to this Docket who desired to participate. All parties to this Docket were notified of the settlement discussion process, were encouraged to participate in the negotiations, and were provided with an equal opportunity to participate.
- 1.4 The terms of this Agreement are just, reasonable, fair, and in the public interest in that they, among other things, establish just and reasonable rates for APS customers; promote the reliability of the electric system, as well as the convenience, comfort and safety, and the preservation of health, of the employees and customers of APS consistent with the Commission's obligations under Arizona law; resolve the issues arising from this Docket; and avoid unnecessary litigation expense and delay.
- 1.5 The Signing Parties believe that this Agreement balances APS's rate increase with benefits for customers. The Signing Parties agree that some of the significant provisions of the Agreement include:
 - a. A \$87.25 million non-fuel, non-depreciation revenue requirement increase, or a reduction of \$58.96 million from APS's original application.
 - b. An average 4.54% bill impact for residential customers compared to an average 7.96% bill impact for residential customers in APS's original application.
 - c. A refund to customers through the Demand Side Management Adjustor Clause ("DSMAC"), of \$15 million in collected, but unspent DSMAC funds to mitigate the first year bill impacts.
 - d. A rate case stay out, in which APS agrees not to file a new general rate case filing prior to June 1, 2019;

- e. A program to expand access to utility owned rooftop solar for low and moderate income Arizonans, Title I Schools, and rural governments;
 - f. Continuation of a buy-through rate for Industrial and large General Service customers;
 - g. Continuation of crisis bill assistance for low income customers;
 - h. More off-peak hours and holidays for time-differentiated rates;
 - i. A moratorium on new self-build generation until January 1, 2022 and through December 31, 2027 for construction of combined-cycle generating units;
 - j. An experimental pilot technology rate initially available for up to 10,000 customers;
 - k. New updated rate designs with rate options for all customers.
 - l. An educational plan and concerted outreach effort by APS on its various rate plans with transitional rates in place until May 1, 2018 to allow for customer education;
 - m. Additional discounts for Schools and Military Customers;
 - n. Resolution of Solar Distributed Generation ("DG") issues for the term of the Settlement Agreement;
 - o. Agreement by Signing Parties to withdraw any appeals of the Commission's Value of Solar Decisions (Docket Nos. 75859 and 75932).
 - p. Agreement by Signing Parties to refrain from pursuing actions in any forum that are inconsistent with the provisions of the Settlement Agreement.
- 1.6 The Signing Parties request that the Commission find that the rates, terms and conditions of this Agreement are just, fair and reasonable and in the public interest in accordance with Article 15, Sections 3 and 14 of the Arizona Constitution and Arizona Revised Statutes Section 40-250 along with any and all other necessary findings, and to approve the Agreement and order that it and the rates contained herein become effective on July 1, 2017.

TERMS AND CONDITIONS

II. RATE CASE STABILITY PROVISION

- 4.2 APS will not file its next general rate case before June 1, 2019. The test year end date for the base rate increase filing contemplated in this section shall be no earlier than December 31, 2018.

III. RATE INCREASE

- 3.1. APS shall receive a \$87.25 million non-fuel, non-depreciation revenue requirement increase. When the reduction for base fuel of \$53.63 million and the increase for depreciation of \$61.00 million is taken into account, the result is a net base rate increase of \$94.624 million, exclusive of the adjustor transfer described below in Paragraph 3.2.
- 3.2 APS also requested to transfer amounts collected in adjustor mechanisms to base rates, which is revenue neutral since the adjustor balances will be reduced with the transfer to base rates. After including the transferred adjustor mechanism amount of \$267.95 million, the Company's total base rate revenue requirement is \$362.58 million ("revenue requirement"). This amount is comprised of: (1) a non-fuel base rate increase of \$148.250 million, which includes a return on and of plant that is in service as of December 31, 2016 ("Post-Test Year Plant"), twelve (12) months beyond the test year ending December 31, 2015 (the "2015 Test Year"); (2) a base fuel rate decrease of \$53.63 million; and (3) the transfer from adjustor mechanisms of \$267.95 million to base rates described in Paragraph VIII herein. When these amounts are netted together, this amounts to a net base rate increase of \$94.624 million.
- 3.3 The Company's jurisdictional fair value rate base used to establish the rates agreed to herein is \$9,990,561,000. APS's total adjusted Test Year revenue is \$2,888,903,000.
- 3.4 In future rate cases, APS will agree to impute net revenue growth for any revenue producing plant included in post-test year plant.

IV. BILL IMPACT

- 4.1 When new rates become effective, customers will have on average a 3.28% bill impact.
- a. Residential customers will have on average a 4.54% bill impact.

- b. General Service customers will have on average a 1.93% bill impact.
- 4.2 To mitigate the first year bill impacts, APS will refund to customers through the DSMAC \$15 million in collected, but unspent DSMAC funds.

V. COST OF CAPITAL

- 5.1 An original cost of capital structure comprised of 44.2% debt and 55.8% common equity shall be adopted for ratemaking purposes for this Docket.
- 5.2 A return on common equity of 10.0% and an embedded cost of debt of 5.13% shall be adopted for ratemaking purposes for this Docket.
- 5.3 The Signing Parties agree to a fair value rate of return of 5.59% for this Docket, which includes a 0.8% return on the fair value increment.
- 5.4 The provisions set forth herein regarding the quantification of fair value rate base, fair value rate of return, and the revenue requirement are made for purposes of settlement only and should not be construed as admissions against interest or waivers of litigation positions related to other or future cases.

VI. DEPRECIATION/AMORTIZATION AND DECOMMISSIONING

- 6.1 APS will lower its proposed annual depreciation expense pro forma on APS's as filed SFR C-2 by \$20 million per year, resulting in a \$61 million increase in depreciation expense (inclusive of the Cholla 2 Regulatory Asset Amortization), by adjusting its proposed lives/net salvage rates for its distribution accounts and by accelerating the amortization of the present excess depreciation reserves for Palo Verde.
- 6.2 The annual depreciation expense for the Palo Verde Nuclear Generating Station will be decreased by \$21 million.
- 6.3 The decrease in Palo Verde depreciation not needed to fund the reduction in revenue requirements described in Section 6.1 above ("Excess Amount") will be offset by a more rapid amortization of the Cholla 2 regulatory asset such that there will be no additional impact on APS's revenue requirement in this case.
- 6.4 Should the Cholla 2 regulatory asset become fully amortized prior to APS's next general rate case, the Excess Amount will be used to accelerate

the recovery of APS's remaining investment in the Navajo Generating Station.

- 6.5 For purposes of settling this rate case, APS's depreciation rates will be deemed to use the straight-line method, vintage group procedure, and remaining life technique.
- 6.6 In APS's next rate case, APS will file a depreciation rate study that includes alternative calculations for cost of removal and dismantlement (negative net salvage) using the "FAS 143" discounted net present value method, computed using a discount rate to be agreed upon.
- 6.7 A copy of APS's agreed upon depreciation rates is attached as Appendix A.
- 6.8 APS's annual nuclear decommissioning expense proposal will be adopted. A copy of the decommissioning contribution schedule is attached as Appendix B.
- 6.9 Subject to the discussion herein of Cholla 2, the Company shall use its proposed amortization rates for regulatory assets and liabilities as well as for other intangibles.

VII. FUEL AND POWER SUPPLY ADJUSTMENT PROVISIONS

- 7.1 The base fuel rate shall be lowered from \$0.032071 per kWh as set in the Decision No. 73183 to \$0.030168 per kWh. This change shall take effect on the effective date of the new rates contained in this Agreement, in accordance with the Plan of Administration for the Power Supply Adjustor ("PSA") to be approved in this case.
- 7.2 APS shall be permitted to include chemical costs for lime, ammonia and sulfur that are incurred in the generation process in the PSA.
- 7.3 APS shall be permitted to include third-party storage expenses in the PSA provided that APS files for approval to include any third-party storage contract with the Commission 90 days before it becomes effective.
- 7.4 The September 30 Preliminary Annual PSA Rate filing and the December 31 Final Annual PSA Rate calculation filing will be consolidated into one annual reset filing that will occur annually on or before November 30. Unless the Commission otherwise acts on the APS calculation by

February 1, the PSA rate proposed by APS will go into effect with the first billing cycle in February.

- 7.5 The PSA Plan of Administration shall be amended as necessary to reflect the terms of this Agreement and shall be approved concurrent with the approval of this Agreement. The revised PSA Plan of Administration is attached as Appendix C.

VIII. TRANSFER OF ITEMS FROM ADJUSTMENT MECHANISMS TO BASE RATES

- 8.1 The Signing Parties agree that certain revenue requirements collected through the Renewable Energy Adjustor Clause ("REAC"), DSMAC Lost Fixed Cost Recovery ("LFCR"), Transmission Cost Adjustor ("TCA"), Environmental Impact Surcharge ("EIS"), Four Corners Rate Rider ("FCRR"), and the System Benefits Charge ("SBC") adjustment mechanisms shall be transferred to base rates and those adjustor rates will be zeroed out or reduced, as proposed by APS herein.
- 8.2 Adjustor transfers agreed to herein shall include the portion of transmission revenue requirements that was collected in the test year for the TCA, the portion of the lost fixed costs that was collected in the test year for the LFCR; the portion of environmental compliance revenue requirements that was collected in the test year for the EIS; an increase in the portion of energy efficiency expense to be collected in base rates from the DSMAC; the revenue requirement of Arizona Sun related renewable generation, the Schools and Governments Program and the Community Power Project will be transferred from the REAC into base rates; the portion of APS's acquisition of Southern California Edison's share of Four Corners currently collected in the Four Corners Rate Rider; and the portion of the System Benefits reduction that went into effect January 1, 2016 to reflect Palo Verde Unit 2 having been fully funded in the nuclear decommissioning trust. The specific amounts in each adjustor to be transferred to base rates pursuant to this Section are identified in Appendix D. The amounts transferred will be calculated using Staff's revenue conversion factor.
- 8.3 On the effective date of the new rates contained in this Agreement, the REAC, DSMAC, LFCR, TCA, EIS, FCRR and SBC rates shall be reduced to reflect the removal of the amounts identified in Appendix D.

IX. RATE TREATMENT RELATED TO THE INSTALLATION OF SELECTIVE CATALYTIC REDUCTIONS AT FOUR CORNERS UNITS 4 AND 5

- 9.1 The parties agree that this Docket shall remain open for the sole purpose of allowing APS to file a request that its rates be adjusted no later than January 1, 2019 to reflect the proposed addition of Selective Catalytic Reduction ("SCR") equipment at Four Corners, as requested in APS's application in this Docket.
- 9.2 APS shall be authorized by the Commission to defer for possible later recovery through rates, all non-fuel costs (as defined herein to include all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt in this proceeding) of owning, operating and maintaining the Selective Catalytic Reduction environmental controls at the Four Corners Power Plant from the date such controls go into service until the inclusion of such costs into rates. Nothing in this paragraph shall be construed in any way to limit this Commission's authority to review the entirety of the project and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision. The interest component of the SCR deferral will be set at APS's embedded cost of debt established in this Agreement.
- 9.3 Any filing seeking a rate adjustment pursuant to Section 9.1 shall include the following schedules: (1) the most current APS balance sheet at the time of filing; (2) the most current APS income statement at the time of filing; (3) an earnings schedule that demonstrates that the operating income resulting from the rate adjustment does not result in a return on rate base in excess of that authorized by this Agreement in the period after the rate adjustment becomes effective; (4) a revenue requirement calculation, including the amortization of any deferred costs; (5) an adjusted rate base schedule; and (6) a typical bill analysis under present and filed rates. The Signing Parties agree to use good faith efforts to process this rate adjustment request such that any resulting rate adjustment becomes effective no later than January 1, 2019, pursuant to Section 9.1.
- 9.4 The Signing Parties shall not present any issues in the rate adjustment proceeding other than those specifically described in this Section.

- 9.5 Section 9 is agreed to without prejudice to any position taken by a Signing Party in any other pending proceeding, including ASBA/AASBO v. ACC, 1 CA-CC-15-0001.

X. COST DEFERRAL RELATED TO THE OCOTILLO MODERNIZATION PROJECT

- 10.1 APS will be authorized to defer for possible later recovery through rates, all non-fuel costs (as defined herein to include all O&M, property taxes, depreciation, and a return at APS's embedded cost of debt in this proceeding) of owning, operating, and maintaining the Ocotillo Modernization Project ("OMP") and retiring the existing steam generation at Ocotillo. Nothing in this paragraph shall be construed in any way to limit the Commission's authority to review the entirety of the project and to make any disallowances thereof due to imprudence, errors or inappropriate application of the requirements of this Decision. The interest component of the Ocotillo deferral will be set at APS's embedded cost of debt established in this Agreement.
- 10.2 The entire OMP will be in service before the rate effective date of APS's next general rate case, and the entire OMP investment will be addressed and resolved in that proceeding.
- 10.3 This agreement does not address the prudence of the OMP, and a deferral of the OMP costs does not guarantee recovery of those costs. Consideration of OMP in APS's next general rate case does not create any precedent, guarantee, or certainty regarding the consideration or treatment of post-test year plant.

XI. COST DEFERRAL RELATED TO CHANGES IN ARIZONA PROPERTY TAX RATE

- 11.1 APS shall be allowed to defer for future recovery (or credit to customers) the Arizona property tax expense above or below the test year caused by changes to the applicable Arizona composite property tax rate.
- 11.2 The property tax deferral will not accrue interest during the deferral period, unless it is negative, in which case, it will accrue interest in favor of APS's customers at APS's short term debt rate.
- 11.3 Beginning with the effective date of the Commission decision resulting from APS's next general rate case, any final property tax rate deferral that

has a positive balance will be recovered from customers over 10 years, with a return at APS's short term debt rate, also with a return on any unrefunded negative balance at the same short term debt rate.

- 11.4 The Signing Parties reserve the right to review APS's property tax deferrals in APS's next general rate case for reasonableness and prudence.
- 11.5 Prior to the next APS general rate case, APS will meet and confer with Staff, RUCO and other stakeholders regarding the appropriate ratemaking treatment for the two year lag on payment of property taxes for post-test year plant.

XII. COST OF SERVICE STUDY

- 12.1 APS agrees in its next rate case to make available to parties its cost of service study in an Excel spreadsheet with inputs linked to outputs so that parties can change the inputs as necessary to reflect their position in the case. APS will meet and confer with stakeholders prior to filing to discuss the cost of service format.
- 12.2 In its next general rate case, APS agrees to perform the Average and Excess methodology to allocate production demand costs to residential and general service classes and then reallocate production demand within the residential sub-classes based on 4CP. This does not preclude APS or other stakeholders from proposing alternative allocation methods.

XIII. NAVAJO GENERATING STATION

- 13.1 APS will address any potential impacts of the closure of the Navajo Generating Station prior to the filing of APS's next rate case in Docket No. E-00000C-17-0039. To the extent it deems appropriate, APS may request that a separate Docket specific to APS be opened to address any issues pertaining to APS's interest in the Navajo Generating Station.

XIV. ANNUAL WORKFORCE PLANNING REPORT

- 14.1 APS shall file a workforce planning report with the Commission containing the following information: (i) the identification of each of the specific challenges or issues APS faces regarding workforce planning; (ii) the specific action(s) APS is taking to address each challenge or issue; and (iii) an update of the progress APS has made toward resolving each challenge or issue. The workforce planning report shall be filed on an annual basis, in this Docket, on or before May 31st, until the conclusion

of the next APS general rate case, and shall be limited to the following job classifications: Electrician-Journeyman, Lineman-Journeyman, Technician-E&I, and Operator-Power Plant (a/k/a Auxiliary Operators and Control Operators). At a minimum, the workforce planning report shall set forth: (i) the number of employees then currently holding these positions; (ii) the present mean and median ages of APS's workforce with respect to these job classifications; (iii) the share of retirement-eligible employees, both as a percentage and in absolute terms, in each of these job classifications; and (iv) the anticipated hiring level and attrition level for each of these job classifications.

- 14.2 The obligation contained in this Section XIV for APS to file a workforce planning report supersedes any prior workforce planning reporting requirement including the requirement in Decision No. 73183.

XV. SELF-BUILD MORATORIUM

- 15.1 APS will not pursue any new self-build generation option having an in-service date prior to January 1, 2022 unless expressly authorized by the Commission. Such restriction shall extend to December 31, 2027 with regard to the construction of combined-cycle generating units.
- 15.2 This self-build moratorium does not include any of the following: (1) the OMP; (2) the acquisition of a generating unit or an interest in a generating unit from a non-affiliated merchant or utility generator; (3) the acquisition of generation needed for system reliability when under the circumstances the seeking of prior Commission approval is impossible or impractical; (4) distributed generation or storage of less than 50 MW per location; (5) microgrids irrespective of size; (6) renewable generation; or (7) uprates or repowering of existing APS-owned generation.
- 15.3 As part of any APS request for Commission authorization to self-build generation, APS will address:
- a. The Company's specific unmet needs for additional long-term resources.
 - b. The Company's efforts to secure adequate and reasonably-priced long-term resources from the competitive wholesale market to meet these needs.

- c. The reasons why APS believes those efforts have been unsuccessful, either in whole or in part.
 - d. The extent to which the request to self-build generation is consistent with any applicable Company resource plans and competitive resource acquisition rules.
 - e. The anticipated cost of the proposed self-build option in comparison with suitable alternatives available from the competitive market for the relevant analysis period.
- 15.4 Nothing in this section shall be construed as relieving APS of its obligation to prudently acquire generating resources, including, but not limited to, seeking the above authorization to self-build a generating resource or resources.
- 15.5 The issuance of any RFP or the conduct of any other competitive solicitation in the future shall not, in and of itself, preclude APS from negotiating bilateral agreements with non-affiliated parties.

XVI. TAX EXPENSE ADJUSTOR MECHANISM

- 16.1 In the event that significant Federal income tax reform legislation is enacted and becomes effective prior to the conclusion of APS's next general rate case, and such legislation materially impacts the Company's annual revenue requirements, APS will create a rate adjustment mechanism to enable the pass-through of income tax effects to customers.
- 16.2 This adjustor mechanism has the following elements:
- a. The change in revenue requirements due to Federal tax reform will be measured as the change in:
 - i. The Federal Income Tax Rate (currently 35%) applied to the Company's Adjusted 2015 Test Year;
 - ii. The annual amortization of any resulting excess deferred income tax regulatory account compared to the Company's Adjusted 2015 Test Year, and;

- iii. Permanent income tax adjustments (such as interest expense and/or property tax expense deductibility) compared to those taken in the Company's Adjusted 2015 Test Year.
- b. The Company will change retail rates through the Tax Expense Adjustor Mechanism (TEAM).
 - i. The rate will be computed on a prospective basis each year based on the jurisdictional retail income tax change as compared to the income tax expense used to set rates in this proceeding combined with the Company's projection of jurisdictional retail sales for the coming year. The rate will be filed on December 1st and will become effective with the first billing cycle in March of each year.
 - ii. The adjustment will be assessed to each customer as an equal per kWh charge.
 - iii. The adjustor mechanism will include a balancing account such that any under- or over-collected balance will be recovered or refunded in the following year.
 - iv. Each year's under- or over-collected balance will accrue interest at the Company's applicable cost of short-term debt.
- 16.3 The TEAM will terminate with the effective date of APS's next general rate case.
- 16.4 The Plan of Administration for the TEAM is attached as Appendix E.

XVII. RESIDENTIAL RATE DESIGN

- 17.1 R-XS: Rate Schedule "R-XS" is available to customers without distributed generation using 600 or less kWh per month on average. The Basic Service Charge for R-XS is \$10 for the average billing month, calculated at a daily rate of \$0.329.
- 17.2 R-Basic: Rate Schedule "R-Basic" is available to customers without distributed generation using more than 600 kWh but less than 1,000 kWh per month on average. The Basic Service Charge for R-Basic is \$15.00 for the average billing month, calculated at a daily rate of \$0.493.

- 17.3 R-Basic Large: Rate Schedule "R-Basic Large" is available to customers without distributed generation using 1,000 kWh per month or more on average. The Basic Service Charge for R-Basic Large is \$20.00 for the average billing month, calculated at a daily rate of \$0.658.
- 17.4 TOU-E: Rate Schedule "TOU-E" is available to all customers. The Basic Service Charge for "TOU-E" is \$13 for the average billing month, calculated at a daily rate of \$0.427. Winter Super Off-peak hours are from 10:00am - 3:00pm. Customers currently on a Time Advantage rate plan will transition to this rate unless they select to voluntarily move to another rate for which they are eligible. For DG customers, the average off-set rate shall be inclusive of the Grid Access Charge described in Section 18.1.
- 17.5 R-2: Rate Schedule "R-2" is a three-part rate available to all customers. The Basic Service Charge for R-2 is \$13 for the average billing month; calculated at a daily rate of \$0.427.
- 17.6 R-3: Rate Schedule R-3 is a three-part rate available to all customers. The Basic Service Charge for R-3 is \$13 for the average billing month; calculated at a daily rate of \$0.427. Customers currently on the Combined Advantage rate plan will transition to this rate unless they select to voluntarily move to another rate for which they are eligible.
- 17.7 R-Tech: An Optional R-Tech Pilot Rate Program shall be created that will initially serve up to 10,000 customers. It is a three-part rate that is available to residential customers when the following criteria are met: (1) two or more qualifying primary on-site technologies were purchased within 90 days of the customer enrolling in the rate; or (2) one qualifying primary on-site technology was purchased within 90 days of the customer enrolling in the rate and two or more qualifying secondary on-site technologies. Qualifying technologies are set forth in Rate Schedule R-Tech attached hereto as Appendix F. The Basic Service Charge for R-Tech is \$15 for the average billing month, calculated at a daily rate of \$0.493.
- a. Once 6,000 customers have signed up to take service under this program, and if such threshold has been reached prior to the Company's next general rate case filing, the Company shall provide notice and promptly convene a meeting of the interested parties to this Docket to discuss the future of the Pilot Program. If

each of the parties to that discussion agree on a new customer participation level for the R-Tech Pilot Program that shall apply until the Commission determines the disposition of the R-Tech Pilot Program during the Company's next general rate case the Company shall file a notice in this Docket to that effect and the program shall continue to be offered up to the new agreed upon customer participation level.

- b. However, if all parties cannot agree to a new customer participation level, then APS shall file a report on the R-Tech Pilot Program and request that the Commission determine whether to continue, expand, or terminate the program in the Docket within 90 days of the date that 7,000 customers have begun taking service under this program. The Commission will then promptly review the program and determine if it should continue, terminate, or be adjusted.
- c. The Signatories have agreed to a rate design for the R-Tech Pilot Rate Program as set forth in Appendix F.

17.8 The on-peak period will be 3:00 pm – 8:00 pm weekdays for TOU-E, R-2, R-3, and R-Tech, excluding holidays specified in Appendix F.

17.9 Attached as Appendix G is the Residential and Commercial rate summary.

XVIII. RESIDENTIAL RATE DESIGN FOR DISTRIBUTED GENERATION CUSTOMERS

- 18.1 DG customers are eligible for four different rate schedules including all proposed TOU and Demand rates. DG customers that select TOU-E will be subject to a Grid Access Charge as reflected in Appendix F.
- 18.2 The self-consumption offset rate for TOU-E will be \$0.105/kWh, which is inclusive of the Grid Access Charge, but exclusive of taxes and adjustors. This is an approximately \$0.120/kWh offset rate after these adjustments. The offset rate is based on the load profile and production profile of APS customers with DG during the test year. Individual customer offset will vary based on individual usage patterns and DG system size, orientation, and production.
- 18.3 The Resource Comparison Proxy Rate ("RCP") for exported energy established in Decision No. 75859, as amended by Decision No. 75932, will be \$0.129/kWh in year one, which is inclusive of undifferentiated

transmission, distribution, and loss components. This export rate was calculated using a 2015 base year with an adjustment to achieve the final export rate. Attached as Appendix H is the RCP Rate Rider, POA and EPR-6 Legacy Rate Rider.

- 18.4 This first year export rate is the product of settlement negotiations and does not create any precedent, imply any change to the structure of or detail in the Resource Comparison Proxy, or otherwise change any aspect of Decision No. 75859.
- 18.5 DG customers that file a completed interconnection application before the rate effective date adopted in the Decision in this case shall be grandfathered consistent with Section 18.6 for a period of twenty years, with the twenty year period beginning from the date the system is interconnected with APS.
- 18.6 As contemplated in Decision No. 75859, grandfathered DG customers will continue to take service under full retail rate net metering and will continue to take service on their current tariff schedule for the length of the grandfathering period, which for APS are rate schedules E-12, ET-1, ET-2, ECT-1, or ECT-2. In its next rate case, APS will propose that the rates on each of these legacy tariffs will be updated with an equal percent increase applied to every rate component equal to the residential average base rate increase approved. In addition, grandfathered DG customers currently served on E-3 or E-4 will continue on the current E-3 or E-4 Rate Riders for as long as they meet the eligibility criteria and/or discontinue participation in the program.

XIX. RESIDENTIAL RATE AVAILABILITY

- 19.1 All customers may select R-Basic, R-Basic Large, TOU-E, R-2, R-3, R-Tech or R-XS if they qualify until May 1, 2018, except to the extent grandfathered under other sections of this Settlement Agreement. Distributed Generation customers will not be eligible for R-XS, R-Basic or R-Basic Large. After May 1, 2018, R-Basic Large will no longer be available to new customers or customers who are on another rate. New customers after May 1, 2018 may choose TOU-E, R-2, R-3 or if they qualify, R-XS or R-Tech. After 90 days, new customers may opt-out of their current rate and select R-Basic if they qualify. Customers transitioning to R-Basic must stay on that rate for at least 12 months.

XX. COMMERCIAL AND INDUSTRIAL RATE DESIGN

- 20.1 APS's General Service XS non-demand rate is adopted and attached as Appendix G.
- 20.2 APS's Aggregation feature and Extra High Load Factor Rate are as proposed by the Company. Copies of these Schedules are attached as Appendix I.
- 20.3 Economic Development Service Schedule 9 is approved as modified by Staff and is attached as Appendix J.
- 20.4 There will be no change to the current net metering structure for non-residential solar customers until addressed in a future Value of Solar or other proceeding.
- 20.5 The Signing Parties agree that issues related to the non-ratchet rate design alternative for C&I remain unresolved by this Agreement, and the Signing Parties agree they may present their respective positions in the hearing scheduled in this proceeding.
- 20.6 The on-peak period will be 3:00 pm – 8:00 pm weekdays for XS through E32-L, but will remain unchanged for E-35.

XXI. E-32L RATE DESIGN

- 21.1 APS agrees to redesign E-32 L in a revenue neutral manner to recover an additional amount of \$1.36 per kW in the unbundled generation charges.

XXII. SCHOOLS DISCOUNT RATE RIDER

- 22.1 All public schools and public school districts will be eligible for a new rate rider. If they apply for service under this rate rider they receive a discount of \$0.0024/kWh.

XXIII. AG-X

- 23.1 The capacity reserve charge applicable to AG-X customers will be equal to \$5.5398 per kW-month (60% of current FERC demand charge of \$9.233 per kW), applied to 100% of the customer's billing demand.

- 23.2 This charge and other parameters will be re-evaluated in APS's next rate case, including whether AG-X should be evaluated as a separate customer class in the cost of service study.
- 23.3 AG-X customers must provide 1-year notice to return to APS's cost-of-service rates. At APS's option, customers seeking to return with less notice must pay market-based rates until the 1-year notice period is attained.
- 23.4 The Administrative Management Fee for the program will be increased to \$1.80 per MWh.
- 23.5 A retail energy imbalance protocol specifically designed to measure how well an AG-X Generation Service Provider ("GSP") is matching its retail buy-through customer load on an hourly basis will replace the FERC energy imbalance protocol. Energy Imbalance will be determined based on each GSP's aggregated hourly customer load.
- a. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, GSPs would pay based on Schedule 4 of APS's OATT, which now reflects the terms of the CAISO imbalance charges.
 - b. Greater than 15% each hour or +/- 2 MW, whichever is greater, in addition to the charges in a.above, GSPs would pay a penalty of \$3 per MWh.
 - c. In addition to the imbalance provisions described above, GSPs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the GSP's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again in a subsequent month, within 12 months from the date of the notice, the GSP's eligibility may be terminated. To avoid termination, a GSP must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of GSP termination, the customer will be required to secure a replacement GSP within 60 days.
- 23.6 The PSA mitigation will remain in place. However the mitigation is modified such that the resale of capacity and energy displaced by AG-X is established at a flat \$1,250,000 per month of off-system sales margins

and excluded from the PSA rather than using a pro-rata share of such margins.

- 23.7 AG-X will remain at 200 MW but the prior restrictions as to 100 MW from each of the E-32L and E-34/35 rate schedules is eliminated; however, 100 MW would be allocated to 20 MW single-site customers with load factors above 70% unless not fully subscribed during the solicitation process.
- 23.8 Line losses for scheduling AG-X load will be modified to reflect transmission voltage service when applicable.
- 23.9 The 10 MW minimum aggregation level will be retained. Current provisions on the size of single site loads eligible for aggregation also will remain in place.
- 23.10 There will be a new lottery if the service is oversubscribed – otherwise, first come, first served. After the initial re-lottery, if necessary, customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.
- 23.11 The AG-1 deferral will be recovered over 5 years from all non-residential customer classes, except the street and area lighting customer classes. The amount will be allocated to each class based on adjusted Test Year kWh. APS will not propose a deferral of unmitigated costs resulting from AG-X, if any, nor propose the collection of unmitigated costs resulting from AG-X, if any, before or in its next rate case. Attached as Appendix K is the AG-X rate schedule.

XXIV. MILITARY CUSTOMERS

- 24.1 The unbundled delivery charge for service at military-primary voltage under rates E-34 and E-35 will be reduced to a level that results in any applicable military customer getting a net impact bill increase equal to the average for all retail customers.

XXV. REVENUE SPREAD

- 25.1 For the revised revenue requirement, APS will keep the same revenue spread between Residential and General Service classes. However, within General Service, because GS extra small and small customers originally had a near zero net bill impact, the reduction will be spread to all other GS

customers proportionally to the original revenue spread. Attached as Appendix L is the revenue spread/targets summary.

XXVI. EFFECTIVE DATE OF RATE PLANS AND TRANSITION PLAN

- 26.1 The rate increase will go into effect on the effective date of the Commission's Decision in this case using transition rates which for purposes of this Agreement are defined as existing Residential and extra small General Service rate schedules with updated revenue requirements. Customers will have the opportunity to select any rate which they qualify for, and APS will provide them information on options that would minimize their bill. Customers that do not select a different rate will transition to the updated rate plan most like their existing rate on or before May 1, 2018. At least 90 days before transitioning customers who have not selected a rate, APS will provide a report to the ACC indicating the total number of customers who have not made a selection.

XXVII. FIVE MILLION DSMAC ALLOCATION

- 27.1 APS will make a one-time allocation of \$5 million from over-collected DSMAC funds to DSM programs for education and to help customers manage new rates and rate options including services and tools available to customers to help them manage their utility costs. APS shall file an outreach and education plan and shall provide stakeholders with an opportunity for review and comment on the draft plan prior to completing its final plan.

XXVIII. AZ SUN II

- 28.1 APS will implement a new program for utility-owned solar distributed generation. The purpose of this program is to expand access to rooftop solar for low and moderate income Arizonans. For this program, distributed generation will be defined as photovoltaic solar generation connected to the distribution system. APS will use third-party solar contractors to install the solar systems. The third-party solar contractors will be competitively selected through an RFP process. APS will own all the generation, renewable energy credits and other attributes from this program.
- 28.2 All reasonable and prudent costs incurred by APS pursuant to this program will be recoverable through the Renewable Energy Adjustment Clause until the next rate case.

- a. Expenses eligible for recovery through the Renewable Energy Adjustment Clause include all O&M expenses, property taxes, marketing and advertising expenses, and the capital carrying costs of any capital investment by APS through this program (depreciation expenses at rates established by the Commission, and return on both debt and equity at the pre-tax weighted average cost of capital).
 - b. APS may request that the capital costs of the solar systems installed under this program be included in rate base in its next rate case.
 - c. APS's expenses under this program may be reviewed for prudence in each annual REST docket. Further, if APS includes any of these solar systems in rate base in the next rate case, those systems will be subject to a prudence review in that case.
 - d. APS will propose a program not less than \$10 million per year, and not more than \$15 million per year, in direct capital costs for the program. At least 65% of annual program will be dedicated to residential installations as defined in subsection 28.4.b. At the end of nine months of each program year, any unspent funds dedicated to low income residential installations can be used for other eligible customers.
 - e. Relation to annual REST docket. The program is approved in this Docket, and APS does not need to seek further approval in the REST Docket for the program or the spending authorized herein. However, APS shall report the number of installations, capital costs, and expenses in each annual REST docket. Further, recovery of the expenses through the Renewable Energy Adjustment Clause will be reviewed in the annual REST dockets as described herein.
- 28.3 This program will be available throughout APS's service area, including in rural Arizona.
- 28.4 This program is limited to low and moderate income residential APS customers as defined below, as well as non-profits that serve low or moderate income APS residential customers, Title I schools, and rural government customers. Rural government is defined as any state, local or tribal government entity in or serving a rural municipality. Rural Municipality means Arizona incorporated cities and towns with

populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area. Metro Area means a city with a population of 750,000 or more and its contiguous and surrounding communities.

- a. Moderate income is defined as a household earning less than 100% of the median Arizona household income. APS will verify the income of each program participant.
 - b. Low income is defined as a household with income at or below 200% of the federal poverty level. APS will verify the income of each program participant.
- 28.5 APS may include any multi-family housing (such as apartment buildings) in the program.
- 28.6 Each residential APS customer participating in the program, upon installation of the solar system, will receive a bill credit of \$10-50 per month applied to their APS bill. APS will work with stakeholders to discuss and determine the reasonable level of bill credit dependent upon type of installation. All other terms and conditions of the customer's rate option will continue to apply.
- 28.7 This program is approved for a period of three years from and after the date APS files a notice of program commencement in this Docket. APS will file the notice no later than three months after the effective date of the Commission's decision in this Docket. APS agrees to not implement any additional utility-owned residential solar distribution generation programs prior to APS's next general rate case beyond AZ Sun II, as outlined above.
- 28.8 APS will file a report with the Commission on the status of the program every quarter during the term of the program. The reporting will list the number of installs in each eligible category until the next APS rate case.

XXIX. LIMITED INCOME PROGRAMS

- 29.1 The E-3 Energy Support Program for limited income customers will be revised to provide eligible customers with a flat 25% bill discount.
- 29.2 The E-4 Medical Support Program for limited income customers who have life sustaining medical equipment will be revised to provide eligible customers with a flat 35% bill discount.

- 29.3 APS agrees to fund \$1.25 million annually the crisis bill program to assist customers whose incomes are less than or equal to 200% of the Federal Poverty Income Guidelines.

XXX. AMI OPT-OUT/SCHEDULE 1

- 30.1 The AMI Opt-Out program will be approved as proposed by APS except the fees will be changed to reflect an upfront fee of \$50 to change out a standard meter for a non-standard meter and monthly fee of \$5. See Service Schedule 1, attached as Appendix M.
- 30.2 Changes to Schedule 1 are attached in Appendix M.

XXXI. SCHEDULE 3

- 31.1 APS will create a new classification in Schedule 3: "Rural Municipal Business Developments" which means a tract of land that has (1) been divided into contiguous lots, (2) is owned and developed by a Rural Municipality and, (3) where the Rural Municipality will be the lease-holder for future, permanent lessee applicants.
- 31.2 Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of an application for service by permanent lessee applicants.
- 31.3 The refund eligibility period will be seven years (Rather than 5 years that applies to other classifications).
- 31.4 Advance payment of one-half of the project costs is due before the start of Company construction. The balance of the project cost will be required 7 years from the Execution Date of the agreement if the project has not become economically feasible by the end of the refundable period. Any unrefunded advance balance paid at the start of the project plus the balance of project costs due at the end of the refund period will become a non-refundable contribution in aid of construction 7 years from the Execution Date of the agreement. (Rather than full advance required before start of construction). Changes to Schedule 3 are attached as Appendix N.

XXXII. LOST FIXED COST RECOVERY MECHANISM

- 32.1 The LFCR opt-out rate option approved in Decision 73183 will be removed.

32.2 The adjustment will no longer be applied to customer's bills as an equal percentage surcharge, but rather as a capacity (demand) charge per kW for customers with a demand rate and as a kWh charge for customers with a two-part rate without demand.

32.3 APS shall submit its LFCR compliance filings on February 15th of each year. New LFCR rates shall take effect, upon Commission approval, with the first billing cycle in May of each year. The LFCR Plan of Administration is attached as Appendix O.

XXXIII. MODIFICATION TO ENVIRONMENTAL IMPROVEMENT SURCHARGE

33.1 APS shall be permitted to increase the cumulative per kWh cap rate for the Environmental Improvement Surcharge ("EIS") from the current \$0.00016 to a new rate of \$0.00050 and include a balancing account.

33.2 A copy of the revised EIS Plan of Administration is attached as Appendix P.

XXXIV. TRANSMISSION COST ADJUSTMENT MECHANISM

34.1 APS shall be permitted to add a balancing account to the TCA.

34.2 Consistent with the Commission's directive in Decision No. 72430, the annual TCA adjustment will become effective June 1 of each year without the need for affirmative Commission approval, consistent with the process approved by the Commission in Decision No. 72430.

34.3 A copy of the proposed TCA Plan of Administration is attached as Appendix Q.

XXXV. CHALLENGES TO DECISION NOS. 75859 AND 75932

35.1 Upon final approval of the Settlement Agreement by way of a final non-appealable Commission Order that includes no material changes to the terms of the Settlement Agreement, all Signing Parties will promptly take all necessary actions to (i) withdraw any challenge to Decision Nos. 75859 and 75932 they have filed, and (ii) refrain from pursuing any legal challenge to Decision Nos. 75859 and 75932 in any forum.

35.2 Prior to the issuance of a non-appealable Commission Order in this rate case, the Signing Parties agree to work together to secure a stay of any and

all appeals that will suspend the filing of all pleadings, motions, briefings, or other court documents, until after the Commission issues its final Order in this case.

XXXVI. POWER SUPPLY ADJUSTOR AUDIT

- 36.1 Staff will docket the final audit report of APS's Power Supply Adjustor ("PSA") and the Signing Parties agree that any issues relating to the PSA audit report will be addressed in the hearing on this matter.

XXXVII. COMPLIANCE MATTERS

- 37.1 Staff's Recommendation for elimination or waiver of certain compliance requirements will be adopted. A list of the items to be eliminated or waived is attached as Appendix R.
- 37.2 Within ten days after the Commission issues an order in this matter, APS shall file compliance schedules associated with this Docket for Staff review. Subject to Staff review, such compliance schedules will become effective on the effective date of the new rates contained in this Agreement.

XXXVIII. FORCE MAJEURE PROVISION

- 38.1 Nothing in this Agreement shall prevent APS from requesting a change to its base rates in the event of conditions or circumstances that constitute an emergency. For the purposes of this Agreement, the term "emergency" is limited to an extraordinary event that, in the Commission's judgment, requires base rate relief in order to protect the public interest. This provision is not intended to preclude any party, including any Signing Party to this Agreement, from opposing an application for rate relief filed by APS pursuant to this paragraph. Nothing in this provision is intended to limit the Commission's ability to change rates at any time pursuant to its lawful authority.

XXXIX. COMMISSION EVALUATION OF PROPOSED SETTLEMENT

- 39.1 All currently filed testimony and exhibits shall be offered into the Commission's record as evidence.
- 39.2 The Signing Parties recognize that Staff does not have the power to bind the Commission. For purposes of proposing a settlement agreement, Staff acts in the same manner as any party to a Commission proceeding.

- 39.3 This Agreement shall serve as a procedural device by which the Signing Parties will submit their proposed settlement of APS's pending rate case, Docket No. E-01345A-16-0036 consolidated with Docket No. E-01345A-16-0123, to the Commission.
- 39.4 The Signing Parties recognize that the Commission will independently consider and evaluate the terms of this Agreement. If the Commission issues an order adopting all material terms of this Agreement, such action shall constitute Commission approval of the Agreement. Thereafter, the Signing Parties shall abide by the terms as approved by the Commission.
- 39.5 If the Commission fails to issue an order adopting all material terms of this Agreement, any or all of the Signing Parties may withdraw from this Agreement, and such Signing Party(ies) may pursue without prejudice their respective remedies at law. For the purposes of this Agreement, whether a term is material shall be left to the discretion of the Signing Party choosing to withdraw from the Agreement. If a Signing Party withdraws from the Agreement pursuant to this paragraph and files an application for rehearing, the other Signing Parties, whether or not the party has withdrawn from the Agreement, except for Staff, shall support the application for rehearing by filing a document with the Commission that supports approval of and future adherence to the Agreement in its entirety. Staff shall not be obligated to file any document or take any position regarding the withdrawing Signing Party's application for rehearing.

XL. MISCELLANEOUS PROVISIONS

- 40.1 This case has attracted a large number of participants with widely diverse interests. To achieve consensus for settlement, many participants are accepting positions that, in any other circumstances, they would be unwilling to accept. They are doing so because this Agreement, as a whole, is consistent with the broad public interest. The acceptance by any Signing Party of a specific element of this Agreement shall not be considered as precedent for acceptance of that element in any other context.
- 40.2 No Signing Party is bound by any position asserted in negotiations, except as expressly stated in this Agreement. No Signing Party shall offer evidence of conduct or statements made in the course of negotiating this Agreement before this Commission, any other regulatory agency, or any court, and no statement, communication or position of any party, their

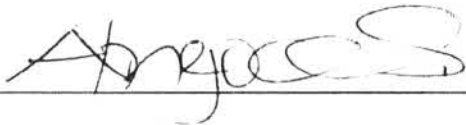
representatives, attorneys, or witnesses in the course of negotiations or in support of this Agreement shall be considered an admission or support for any position taken in any other forum or action.

- 40.3 Neither this Agreement nor any of the positions taken in this Agreement by any of the Signing Parties may be referred to, cited, or relied upon as precedent in any proceeding before the Commission, any other regulatory agency, or any court for any purpose except to secure approval of this Agreement and enforce its terms.
- 40.4 To the extent any provision of this Agreement is inconsistent with any existing Commission order, rule, or regulation, this Agreement shall control.
- 40.5 Each of the terms of this Agreement is in consideration of all other terms of this Agreement. Accordingly, the terms are not severable.
- 40.6 The Signing Parties shall make reasonable and good faith efforts necessary to obtain a Commission order approving this Agreement. The Signing Parties shall support and defend this Agreement before the Commission. Subject to subsection 40.5, if the Commission adopts an order approving all material terms of the Agreement, the Signing Parties will support and defend the Commission's order before any court or regulatory agency in which it may be at issue.
- 40.7 This Agreement may be executed in any number of counterparts and by each Signing Party on separate counterparts, each of which when so executed and delivered shall be deemed an original and all of which taken together shall constitute one and the same instrument. This Agreement may also be executed electronically or by facsimile.

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

ARIZONA CORPORATION COMMISSION

By: 

Name: Elijah Abinah

Title: Acting Director, Utilities Division

Date: March 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

Arizona Public Service Company

By: Barbara Lockwood

Name: Barbara Lockwood

Title: Vice President, Regulation

Date: March 24, 2017

Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123

SIGNATURE PAGE

Residential Utility Consumer Office

By: David Tenney

Name: David Tenney

Title: Director

Date: 3/28/17

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

[Arizona Utility Ratepayer Alliance]

By:  _____

Name: Patrick J Quinn

Title: Managing Partner

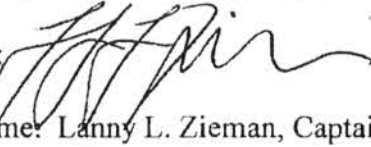
Date: March 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

FEDERAL EXECUTIVE AGENCIES

By:



Name: Lanny L. Zieman, Captain, USAF

Title: Utilities Litigation Attorney

Date: 24 March 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

**ARIZONA SOLAR DEPLOYMENT
ALLIANCE**

By: 

Name: SEAN M. SEITZ

Title: PRESIDENT

Date: MARCH 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

[INSERT PARTY NAME/COMPANY]

By: Thomas A. Harris

Name: Tom Harris

Title: Treasurer, AriSEIA

Date: Mar. 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

Vote Solar


[INSERT PARTY NAME/COMPANY]

By:

Name:

Title:

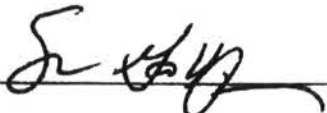
Date:


Adam Brown
Executive Director
2/24/17

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

Solar Energy Industries Association

By: _____

Name: Sean Gallagher

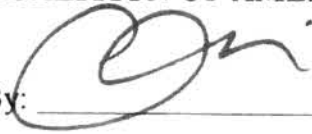
Title: Vice-President State Affairs

Date: 3/24/17

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

**ENERGY FREEDOM
COALITION OF AMERICA**

By: 

Name: Court S. Rich

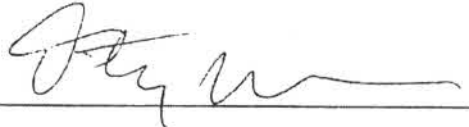
Title: Attorney for Energy Freedom
Coalition of America, LLC

Date: 3/27/17

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

Arizona School Boards Association and the
Arizona Association of School Business
Officials

By: _____

Name: Timothy M. Hogan

Title: Attorney

Date: 3/23/17

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

**ARIZONANS FOR ELECTRIC
CHOICE AND COMPETITION**

By: 

Name: Stan Barnes

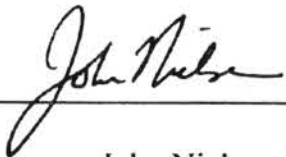
Title: President

Date: March 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

WESTERN RESOURCE ADVOCATES

By: 

Name: John Nielsen

Title: Clean Energy Program Director

Date: 3/24/2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

Wal-Mart Stores, Inc. and Sam's West, Inc.

By: Scott Wakefield

Name: Scott Wakefield

Title: Attorney

Date: March 24, 2017

Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123

LUBIN & ENOCH, P.C.

By: _____

Name: Nicholas J. Enoch, Esq.

Title: Attorney for Intervenors

IBEW Locals 387 & 769

Date: March 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

**FREEPORT MINERALS
CORPORATION**

By: Michael McElrath

Name: Michael McElrath

Title: Director Energy

Date: March 29, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

[INSERT PARTY NAME/COMPANY]

By: _____


Name: Cynthia Zwick

Title: Executive Director,
Arizona Community Action Assoc.

Date: March 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

[INSERT PARTY NAME/COMPANY]

By: _____

Name: _____

Title: _____

Date: _____

K. Boehm

KURT BOEHM

ATTORNEY, The Kroger Co

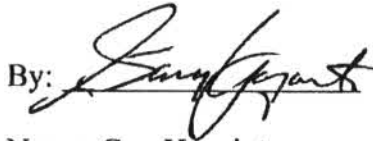
3/24/2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

ARIZONA INVESTMENT COUNCIL

By:



Name: Gary Yaquinto

Title: President & CEO

Date: 3/24/2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

Property Owners & Residents Association
(PORA) Sun City West

By: Al Gervenack

Name: Al Gervenack _____

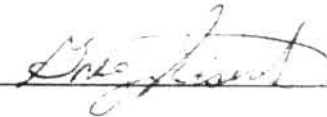
Title: Director, Board of Directors

Date: March 24, 2017 _____

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

[SUN CITY HOME OWNERS
ASSOCIATION (SCHOA)]

By: 

Name: GREG EISERT

Title: Director, Chairman of Government
Affairs

Date: 24 March 2017

Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123

SIGNATURE PAGE

REP America d/b/a ConservAmerica

By: Timothy J. Sade

Name: Timothy J. Sade

Title: Attorney for ConservAmerica

Date: 3/29/17

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

Constellation New Energy, LLC

By: Lawrence V. Robertson, Jr.

Name: Lawrence V. Robertson, Jr.

Title: Attorney

Date: March 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

Direct Energy Business, LLC

By: Lawrence V. Robertson, Jr.

Name: Lawrence V. Robertson, Jr.

Title: Attorney

Date: March 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

Calpine Energy Solutions, LLC

By: Lawrence V. Robertson, Jr.

Name: Lawrence V. Robertson, Jr.

Title: Attorney

Date: March 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

[Arizona Competitive Power Alliance]

By:  _____

Name: Greg Patterson

Title: AzCPA Director

Date: March 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

CITY OF COOLIDGE

By: _____

Name: Denis M. Fitzgibbons


Title: City of Attorney

Date: March 24, 2017

**Arizona Public Service Company
Proposed Settlement Agreement
Docket Nos. E-01345A-16-0036 & E-01345A-16-0123**

SIGNATURE PAGE

Granite Creek Farms LLC
Granite Creek Power & Gas LLC

By: 
Name: Thomas E Stewart _____

Title: General Manager _____

Date: 3/26/2017 _____



Settlement Agreement Appendix Index

A	Depreciation Rates
B	Annual Nuclear Decommissioning Expense
C	PSA Plan of Administration
D	Adjustors Transferred to Base Rates
E	TEAM Plan of Administration
F	R-XS, R-Basic, R-Basic Large, TOU-E, R-2, R-3 Rate Schedules, R-Tech Pilot Rate
G	Residential and Commercial Rate Summary
H	RCP Rate Rider and POA, EPR-6, and EPR-6 Legacy Rate Rider
I	E-32L, E-32L TOU, XHLF Rate Schedule
J	Service Schedule 9
K	AG-X Rate Schedule
L	Revenue Spread/Targets
M	Service Schedule 1
N	Service Schedule 3
O	LFCR Plan of Administration
P	EIS Plan of Administration
Q	TCA Plan of Administration
R	Compliance Requirements Eliminated or Waived

Appendix A

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description A	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment B	Net Salvage C	Total D=B+C	Investment E	Net Salvage F	Total G=E+F
STEAM PRODUCTION						
311.00 Structures and Improvements	2.52%	0.30%	2.82%	5.01%	0.42%	5.43%
312.00 Boiler Plant Equipment	2.17%	0.32%	2.49%	3.78%	0.39%	4.17%
314.00 Turbogenerator Units	2.51%	0.33%	2.84%	4.45%	0.50%	4.95%
315.00 Accessory Electric Equipment	2.27%	0.34%	2.61%	4.50%	0.47%	4.97%
316.00 Miscellaneous Power Plant Equipment	2.46%	0.33%	2.79%	4.77%	0.59%	5.36%
Total Steam Production Plant	2.27%	0.32%	2.59%	4.08%	0.42%	4.50%
NUCLEAR PRODUCTION						
321.00 Structures and Improvements	1.34%	0.01%	1.35%	0.96%	0.02%	0.98%
322.00 Reactor Plant Equipment	1.50%	0.05%	1.55%	0.77%	0.06%	0.83%
323.00 Turbogenerator Units	1.45%	0.02%	1.47%	0.89%	0.03%	0.92%
324.00 Accessory Electric Equipment	1.19%	0.01%	1.20%	0.39%	0.01%	0.40%
325.00 Miscellaneous Power Plant Equipment	1.51%	0.04%	1.55%	1.30%	0.05%	1.35%
Total Nuclear Production Plant	1.42%	0.03%	1.45%	0.84%	0.03%	0.87%
OTHER PRODUCTION						
341.00 Structures and Improvements	3.04%	-0.09%	2.95%	3.60%	0.26%	3.86%
342.00 Fuel Holders, Products and Accessories	3.14%	-0.15%	2.99%	3.62%	0.19%	3.81%
343.00 Prime Movers	2.40%	-0.10%	2.30%	3.28%	0.15%	3.43%
344.00 Generators and Devices	3.30%	-0.32%	2.98%	3.86%	0.12%	3.98%
345.00 Accessory Electric Equipment	3.11%	-0.06%	3.05%	3.71%	0.24%	3.95%
346.00 Miscellaneous Power Plant Equipment	3.35%	-0.15%	3.20%	4.08%	0.21%	4.29%
Total Other Production Plant	3.02%	-0.22%	2.80%	3.67%	0.15%	3.82%
TRANSMISSION PLANT						
352.02 Structures and Improvements	2.67%		2.67%	2.51%		2.51%
353.00 Station Equipment	2.31%	0.11%	2.42%	1.91%	0.09%	2.00%
354.00 Towers and Fixtures	1.84%		1.84%	1.78%		1.78%
355.00 Poles and Fixtures	1.86%	0.37%	2.23%	1.85%	0.37%	2.22%
356.00 Overhead Conductors and Devices	1.75%	0.33%	2.08%	1.74%	0.33%	2.07%
Total Transmission Plant	2.29%	0.11%	2.40%	1.91%	0.09%	2.00%
DISTRIBUTION PLANT						
361.00 Structures and Improvements	1.57%	0.07%	1.64%	1.58%	0.08%	1.66%
362.00 Station Equipment	2.19%	-0.20%	1.99%	2.20%	0.08%	2.28%
363.00 Storage Battery Equipment	6.67%		6.67%	8.79%		8.79%
364.01 Poles, Towers and Fixtures - Wood	2.29%	-0.02%	2.27%	2.10%	0.19%	2.29%
364.02 Poles, Towers and Fixtures - Steel	2.55%	0.26%	2.81%	1.95%	0.19%	2.14%
365.00 Overhead Conductors and Devices	1.98%	-0.08%	1.90%	1.92%	0.20%	2.12%
366.00 Underground Conduit	1.57%	0.08%	1.65%	1.57%	0.17%	1.74%
367.00 Underground Conductors and Devices	2.63%	0.09%	2.72%	2.34%	0.20%	2.54%
368.00 Line Transformers	1.68%	0.07%	1.75%	1.70%	0.06%	1.76%
369.00 Services	2.20%	0.10%	2.30%	1.68%	0.33%	2.01%
370.01 Meters - Electronic	3.68%		3.68%	5.52%	-0.03%	5.49%
370.03 Meters - AMI	3.82%		3.82%	4.84%		4.84%
371.00 Installations on Customers' Premises	2.34%	0.34%	2.68%	2.11%	0.31%	2.42%
373.00 Street Lighting and Signal Systems	1.72%	0.13%	1.85%	1.72%	0.18%	1.90%
Total Distribution Plant	2.25%	0.05%	2.30%	2.14%	0.16%	2.30%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.19%	0.13%	2.32%	2.52%	0.17%	2.69%
391.00 Office Furn. and Equip. - Computer	12.08%	0.02%	12.10%	12.86%	0.02%	12.88%
397.00 Communication Equipment	5.35%		5.35%	4.83%		4.83%
Total Depreciable	6.30%	0.04%	6.34%	6.40%	0.06%	6.46%

ARIZONA PUBLIC SERVICE COMPANY

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement A

Account Description A	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment B	Net Salvage C	Total D=B+C	Investment E	Net Salvage F	Total G=E+F
Amortizable						
391.FE Office Furn. and Equip. - Furniture	← 20 Year Amortization →			← 20 Year Amortization →		
393.00 Stores Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
394.00 Tools, Shop and Garage Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
395.00 Laboratory Equipment	← 20 Year Amortization →			← 20 Year Amortization →		
398.00 Miscellaneous Equipment	← 24 Year Amortization →			← 24 Year Amortization →		
Total Amortizable	4.86%		4.86%	4.86%		4.86%
Total General Plant	6.07%	0.04%	6.11%	6.15%	0.05%	6.20%
TOTAL UTILITY	2.42%	0.03%	2.45%	2.61%	0.16%	2.77%
STEAM PRODUCTION (by Unit)						
<u>Cholla</u>						
311.00 Structures and Improvements	2.85%	0.14%	2.99%	7.05%	0.50%	7.55%
312.00 Boiler Plant Equipment	3.56%	0.25%	3.81%	7.02%	0.57%	7.59%
314.00 Turbogenerator Units	3.53%	0.18%	3.71%	6.64%	0.46%	7.10%
315.00 Accessory Electric Equipment	2.55%	0.14%	2.69%	6.10%	0.43%	6.53%
316.00 Miscellaneous Power Plant Equipment	3.00%	0.20%	3.20%	7.37%	0.55%	7.92%
Total Cholla	3.36%	0.22%	3.58%	6.90%	0.54%	7.44%
<u>Cholla Unit 1</u>						
311.00 Structures and Improvements	3.60%	0.17%	3.77%	5.36%	0.44%	5.80%
312.00 Boiler Plant Equipment	4.22%	0.26%	4.48%	6.04%	0.65%	6.69%
314.00 Turbogenerator Units	4.59%	0.24%	4.83%	6.37%	0.58%	6.95%
315.00 Accessory Electric Equipment	3.65%	0.19%	3.84%	5.48%	0.48%	5.96%
316.00 Miscellaneous Power Plant Equipment	3.45%	0.19%	3.64%	5.15%	0.45%	5.60%
Total Cholla Unit 1	4.22%	0.25%	4.47%	6.02%	0.61%	6.63%
<u>Cholla Unit 3</u>						
311.00 Structures and Improvements	2.19%	0.10%	2.29%	7.02%	0.46%	7.48%
312.00 Boiler Plant Equipment	3.40%	0.25%	3.65%	7.28%	0.55%	7.83%
314.00 Turbogenerator Units	3.04%	0.15%	3.19%	6.72%	0.39%	7.11%
315.00 Accessory Electric Equipment	2.16%	0.12%	2.28%	5.99%	0.42%	6.41%
316.00 Miscellaneous Power Plant Equipment	2.48%	0.15%	2.63%	7.24%	0.52%	7.76%
Total Cholla Unit 3	3.15%	0.21%	3.36%	7.05%	0.51%	7.56%
<u>Cholla Common</u>						
311.00 Structures and Improvements	2.94%	0.15%	3.09%	7.19%	0.52%	7.71%
312.00 Boiler Plant Equipment	3.32%	0.25%	3.57%	7.27%	0.60%	7.87%
314.00 Turbogenerator Units	2.67%	0.13%	2.80%	8.50%	0.63%	9.13%
315.00 Accessory Electric Equipment	2.96%	0.18%	3.14%	7.29%	0.47%	7.76%
316.00 Miscellaneous Power Plant Equipment	3.16%	0.22%	3.38%	7.89%	0.59%	8.48%
Total Cholla Common	3.12%	0.20%	3.32%	7.31%	0.56%	7.87%
<u>Four Corners</u>						
311.00 Structures and Improvements	1.35%	0.51%	1.86%	2.36%	0.26%	2.62%
312.00 Boiler Plant Equipment	0.85%	0.37%	1.22%	1.52%	0.26%	1.78%
314.00 Turbogenerator Units	0.95%	0.42%	1.37%	1.60%	0.30%	1.90%
315.00 Accessory Electric Equipment	1.40%	0.56%	1.96%	2.59%	0.39%	2.98%
316.00 Miscellaneous Power Plant Equipment	1.09%	0.29%	1.38%	2.30%	0.39%	2.69%
Total Four Corners	0.94%	0.39%	1.33%	1.69%	0.28%	1.97%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description A	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment B	Net Salvage C	Total D=B+C	Investment E	Net Salvage F	Total G=E+F
Four Corners Units 4-5						
311.00 Structures and Improvements	0.98%	0.52%	1.50%	1.75%	0.31%	2.06%
312.00 Boiler Plant Equipment	0.77%	0.36%	1.13%	1.40%	0.24%	1.64%
314.00 Turbogenerator Units	0.92%	0.43%	1.35%	1.55%	0.30%	1.85%
315.00 Accessory Electric Equipment	1.06%	0.57%	1.63%	2.12%	0.41%	2.53%
316.00 Miscellaneous Power Plant Equipment	0.54%	0.18%	0.72%	2.02%	0.40%	2.42%
Total Four Corners Units 4-5	0.80%	0.38%	1.18%	1.50%	0.26%	1.76%
Four Corners Common						
311.00 Structures and Improvements	2.23%	0.48%	2.71%	3.81%	0.16%	3.97%
312.00 Boiler Plant Equipment	2.09%	0.49%	2.58%	3.44%	0.44%	3.88%
314.00 Turbogenerator Units	1.65%	0.28%	1.93%	2.87%	0.27%	3.14%
315.00 Accessory Electric Equipment	2.39%	0.53%	2.92%	3.93%	0.36%	4.29%
316.00 Miscellaneous Power Plant Equipment	2.50%	0.58%	3.08%	3.03%	0.34%	3.37%
Total Four Corners Common	2.21%	0.50%	2.71%	3.50%	0.35%	3.85%
Navajo Units 1-3						
311.00 Structures and Improvements	3.34%	0.24%	3.58%	3.78%	0.20%	3.98%
312.00 Boiler Plant Equipment	3.42%	0.28%	3.70%	3.52%	0.19%	3.71%
314.00 Turbogenerator Units	2.71%	0.20%	2.91%	2.72%	0.15%	2.87%
315.00 Accessory Electric Equipment	2.93%	0.21%	3.14%	3.06%	0.17%	3.23%
316.00 Miscellaneous Power Plant Equipment	3.75%	0.29%	4.04%	4.19%	0.29%	4.48%
Total Navajo Units 1-3	3.33%	0.26%	3.59%	3.49%	0.19%	3.68%
Ocotillo Units 1-2						
311.00 Structures and Improvements	4.91%	0.88%	5.79%	10.65%	2.28%	12.93%
312.00 Boiler Plant Equipment	3.41%	0.65%	4.06%	8.89%	1.97%	10.86%
314.00 Turbogenerator Units	4.74%	0.88%	5.62%	9.88%	2.25%	12.13%
315.00 Accessory Electric Equipment	4.55%	0.84%	5.39%	12.68%	2.76%	15.44%
316.00 Miscellaneous Power Plant Equipment	5.80%	1.10%	6.90%	13.34%	2.76%	16.10%
Total Ocotillo Units 1-2	4.30%	0.80%	5.10%	10.17%	2.23%	12.40%
NUCLEAR PRODUCTION (by Unit)						
Palo Verde						
321.00 Structures and Improvements	1.34%	0.01%	1.35%	0.96%	0.02%	0.98%
322.00 Reactor Plant Equipment	1.50%	0.05%	1.55%	0.77%	0.06%	0.83%
323.00 Turbogenerator Units	1.45%	0.02%	1.47%	0.89%	0.03%	0.92%
324.00 Accessory Electric Equipment	1.19%	0.01%	1.20%	0.39%	0.01%	0.40%
325.00 Miscellaneous Power Plant Equipment	1.51%	0.04%	1.55%	1.30%	0.05%	1.35%
Total Palo Verde	1.42%	0.03%	1.45%	0.84%	0.03%	0.87%
Palo Verde Unit 1						
321.00 Structures and Improvements	1.13%		1.13%	0.18%	0.00%	0.19%
322.00 Reactor Plant Equipment	1.45%	0.04%	1.49%	0.60%	0.01%	0.62%
323.00 Turbogenerator Units	1.41%	0.02%	1.43%	0.79%	0.05%	0.83%
324.00 Accessory Electric Equipment	1.11%	0.01%	1.12%	0.19%	0.00%	0.20%
325.00 Miscellaneous Power Plant Equipment	1.29%	0.02%	1.31%	0.40%	0.04%	0.43%
Total Palo Verde Unit 1	1.34%	0.03%	1.37%	0.50%	0.01%	0.51%
Palo Verde Unit 2						
321.00 Structures and Improvements	1.20%	0.01%	1.21%	0.37%	0.00%	0.37%
322.00 Reactor Plant Equipment	1.52%	0.08%	1.60%	0.96%	0.06%	1.02%
323.00 Turbogenerator Units	1.41%	0.01%	1.42%	1.11%	0.03%	1.14%
324.00 Accessory Electric Equipment	1.25%	0.01%	1.26%	0.47%	0.01%	0.48%
325.00 Miscellaneous Power Plant Equipment	1.45%	0.02%	1.47%	0.69%	0.03%	0.72%
Total Palo Verde Unit 2	1.41%	0.05%	1.46%	0.82%	0.03%	0.85%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description A	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment B	Net Salvage C	Total D=B+C	Investment E	Net Salvage F	Total G=E+F
<u>Palo Verde Unit 3</u>						
321.00 Structures and Improvements	1.22%		1.22%	0.29%	0.00%	0.29%
322.00 Reactor Plant Equipment	1.56%	0.05%	1.61%	0.81%	0.09%	0.90%
323.00 Turbogenerator Units	1.48%	0.02%	1.50%	0.81%	0.01%	0.83%
324.00 Accessory Electric Equipment	1.24%	0.01%	1.25%	0.39%	0.01%	0.41%
325.00 Miscellaneous Power Plant Equipment	1.36%	0.02%	1.38%	0.55%	0.04%	0.59%
Total Palo Verde Unit 3	1.44%	0.03%	1.47%	0.66%	0.05%	0.71%
<u>Palo Verde Water Reclamation</u>						
321.00 Structures and Improvements	1.69%	0.02%	1.71%	2.05%	0.03%	2.08%
322.00 Reactor Plant Equipment	2.01%	0.03%	2.04%	2.92%	0.04%	2.96%
323.00 Turbogenerator Units	1.45%	0.01%	1.46%	1.43%	0.17%	1.60%
324.00 Accessory Electric Equipment						
325.00 Miscellaneous Power Plant Equipment	1.43%	0.05%	1.48%	2.19%	0.01%	2.20%
Total Palo Verde Water Reclamation	1.69%	0.02%	1.71%	2.05%	0.04%	2.09%
<u>Palo Verde Common</u>						
321.00 Structures and Improvements	1.30%	0.02%	1.32%	1.31%	0.02%	1.34%
322.00 Reactor Plant Equipment	1.22%	0.06%	1.28%	0.98%	0.42%	1.40%
323.00 Turbogenerator Units	2.15%	0.04%	2.19%	2.31%	0.24%	2.54%
324.00 Accessory Electric Equipment	1.21%	0.01%	1.22%	1.08%	0.01%	1.09%
325.00 Miscellaneous Power Plant Equipment	1.64%	0.06%	1.70%	1.94%	0.06%	2.00%
Total Palo Verde Common	1.40%	0.04%	1.44%	1.46%	0.08%	1.54%
OTHER PRODUCTION (by Unit)						
<u>Douglas CT</u>						
341.00 Structures and Improvements	5.13%	-0.26%	4.87%	16.13%	0.81%	16.94%
342.00 Fuel Holders, Products and Accessories	0.90%	-0.01%	0.89%	24.09%	1.08%	25.17%
343.00 Prime Movers	-0.25%	0.02%	-0.23%	11.37%	-9.17%	2.20%
344.00 Generators and Devices	-0.28%	0.01%	-0.27%	18.97%	0.95%	19.92%
345.00 Accessory Electric Equipment	0.02%	0.02%	0.04%	23.54%	1.09%	24.63%
346.00 Miscellaneous Power Plant Equipment	0.70%	-0.03%	0.67%	24.08%	1.28%	25.36%
Total Douglas CT	-0.10%	0.01%	-0.09%	14.16%	-6.05%	8.11%
<u>Ocotillo CT Units 1-2</u>						
341.00 Structures and Improvements	4.19%	-0.20%	3.99%	5.50%	0.48%	5.98%
342.00 Fuel Holders, Products and Accessories	2.07%	-0.10%	1.97%	3.72%	0.19%	3.91%
343.00 Prime Movers	0.73%	-0.03%	0.70%	5.41%	0.70%	6.11%
344.00 Generators and Devices	3.44%	-0.61%	2.83%	4.73%	0.25%	4.98%
345.00 Accessory Electric Equipment	1.60%	-0.06%	1.54%	4.84%	0.27%	5.11%
346.00 Miscellaneous Power Plant Equipment	2.14%	-0.09%	2.05%	4.18%	0.20%	4.38%
Total Ocotillo CT Units 1-2	1.91%	-0.23%	1.68%	5.07%	0.48%	5.55%
<u>Redhawk CC Units 1-2</u>						
341.00 Structures and Improvements	3.13%	-0.12%	3.01%	4.00%	0.20%	4.20%
342.00 Fuel Holders, Products and Accessories	3.63%	-0.18%	3.45%	4.37%	0.23%	4.60%
343.00 Prime Movers	3.11%	-0.08%	3.03%	3.97%	0.26%	4.23%
344.00 Generators and Devices	3.33%	-0.83%	2.50%	4.33%	-0.11%	4.22%
345.00 Accessory Electric Equipment	3.11%	-0.10%	3.01%	3.97%	0.19%	4.16%
346.00 Miscellaneous Power Plant Equipment	3.60%	-0.18%	3.42%	4.41%	0.20%	4.61%
Total Redhawk CC Units 1-2	3.27%	-0.56%	2.71%	4.21%	0.02%	4.23%

ARIZONA PUBLIC SERVICE COMPANY

Component Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Statement A

Account Description A	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment B	Net Salvage C	Total D=B+C	Investment E	Net Salvage F	Total G=E+F
Saguaro						
341.00 Structures and Improvements	4.60%	-0.22%	4.38%	4.20%	0.41%	4.61%
342.00 Fuel Holders, Products and Accessories	1.27%	-0.03%	1.24%	2.16%	0.13%	2.29%
343.00 Prime Movers	0.71%	-0.03%	0.68%	4.09%	0.47%	4.56%
344.00 Generators and Devices	2.92%	-0.19%	2.73%	2.97%	0.15%	3.12%
345.00 Accessory Electric Equipment	0.55%	-0.01%	0.54%	4.08%	0.25%	4.33%
346.00 Miscellaneous Power Plant Equipment	2.57%	-0.12%	2.45%	2.25%	0.11%	2.36%
Total Saguaro	2.16%	-0.13%	2.03%	3.40%	0.27%	3.67%
Saguaro CT Units 1-2						
341.00 Structures and Improvements	4.60%	-0.22%	4.38%	4.20%	0.41%	4.61%
342.00 Fuel Holders, Products and Accessories	1.27%	-0.03%	1.24%	2.16%	0.13%	2.29%
343.00 Prime Movers	0.45%	-0.02%	0.43%	4.10%	0.50%	4.60%
344.00 Generators and Devices	3.36%	-0.52%	2.84%	2.72%	0.15%	2.87%
345.00 Accessory Electric Equipment	0.46%	-0.01%	0.45%	4.12%	0.25%	4.37%
346.00 Miscellaneous Power Plant Equipment	2.57%	-0.12%	2.45%	2.25%	0.11%	2.36%
Total Saguaro CT Units 1-2	1.46%	-0.12%	1.34%	3.73%	0.38%	4.11%
Saguaro CT Unit 3						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	2.85%	-0.14%	2.71%	3.99%	0.20%	4.19%
344.00 Generators and Devices	2.85%	-0.14%	2.71%	3.01%	0.15%	3.16%
345.00 Accessory Electric Equipment	2.85%	-0.14%	2.71%	3.00%	0.16%	3.16%
346.00 Miscellaneous Power Plant Equipment						
Total Saguaro CT Unit 3	2.85%	-0.14%	2.71%	3.07%	0.16%	3.23%
Solar Units						
341.00 Structures and Improvements						
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices						
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total Solar Units	3.36%	-0.01%	3.35%	3.58%	0.28%	3.86%
Chino Valley						
341.05 Structures and Improvements	3.33%		3.33%	3.53%	0.26%	3.79%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.53%	0.26%	3.79%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.53%	0.26%	3.79%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.53%	0.26%	3.79%
Total Chino Valley	3.33%		3.33%	3.53%	0.26%	3.79%
Cotton Center						
341.05 Structures and Improvements	3.33%		3.33%	3.52%	0.24%	3.76%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.52%	0.24%	3.76%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.52%	0.24%	3.76%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.52%	0.24%	3.76%
Total Cotton Center	3.33%		3.33%	3.52%	0.24%	3.76%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

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Account Description A	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment B	Net Salvage C	Total D=B+C	Investment E	Net Salvage F	Total G=E+F
Desert Star						
341.05 Structures and Improvements	3.33%		3.33%	4.51%	0.52%	5.03%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	4.51%	0.52%	5.03%
345.05 Accessory Electric Equipment	3.33%		3.33%	4.51%	0.52%	5.03%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	4.51%	0.52%	5.03%
Total Desert Star	3.33%		3.33%	4.51%	0.52%	5.03%
Foothills Units 1-2						
341.05 Structures and Improvements	3.33%		3.33%	3.48%	0.30%	3.78%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.48%	0.30%	3.78%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.48%	0.30%	3.78%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.48%	0.30%	3.78%
Total Foothills Units 1-2	3.33%		3.33%	3.48%	0.30%	3.78%
Gila Bend						
341.05 Structures and Improvements	3.33%		3.33%	3.46%	0.36%	3.82%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.46%	0.36%	3.82%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.46%	0.36%	3.82%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.46%	0.36%	3.82%
Total Gila Bend	3.33%		3.33%	3.46%	0.36%	3.82%
Hyder Units 1-2						
341.05 Structures and Improvements	3.33%		3.33%	3.51%	0.16%	3.67%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.50%	0.16%	3.66%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.48%	0.16%	3.64%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.42%	0.15%	3.57%
Total Hyder Units 1-2	3.33%		3.33%	3.50%	0.16%	3.66%
Legacy Units						
341.00 Structures and Improvements	-3.55%	0.20%	-3.35%	1.31%	0.03%	1.34%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices	3.93%	-0.86%	3.07%	3.44%	0.08%	3.52%
345.00 Accessory Electric Equipment	7.41%	-0.37%	7.04%	4.23%	0.22%	4.45%
346.00 Miscellaneous Power Plant Equipment						
Total Legacy Units	4.65%	-0.71%	3.94%	3.59%	0.12%	3.71%
Luke AFB						
341.05 Structures and Improvements	3.33%		3.33%	4.51%	0.54%	5.05%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	4.51%	0.54%	5.05%
345.05 Accessory Electric Equipment	3.33%		3.33%	4.51%	0.54%	5.05%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	4.51%	0.54%	5.05%
Total Luke AFB	3.33%		3.33%	4.51%	0.54%	5.05%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates

Current: VG Procedure / RL Technique

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Account Description A	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment B	Net Salvage C	Total D=B+C	Investment E	Net Salvage F	Total G=E+F
Roof Tops						
341.05 Structures and Improvements	3.33%		3.33%	3.53%	0.18%	3.71%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.55%	0.18%	3.73%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.54%	0.18%	3.72%
346.05 Miscellaneous Power Plant Equipment						
Total Roof Tops	3.33%		3.33%	3.55%	0.18%	3.73%
Paloma						
341.05 Structures and Improvements	3.33%		3.33%	3.52%	0.30%	3.82%
342.05 Fuel Holders, Products and Accessories						
343.05 Prime Movers						
344.05 Generators and Devices	3.33%		3.33%	3.52%	0.30%	3.82%
345.05 Accessory Electric Equipment	3.33%		3.33%	3.52%	0.30%	3.82%
346.05 Miscellaneous Power Plant Equipment	3.33%		3.33%	3.52%	0.30%	3.82%
Total Paloma	3.33%		3.33%	3.52%	0.30%	3.82%
Sundance						
341.00 Structures and Improvements	2.06%	-0.10%	1.96%	2.49%	0.23%	2.72%
342.00 Fuel Holders, Products and Accessories	2.05%	-0.10%	1.95%	2.45%	0.12%	2.57%
343.00 Prime Movers	2.04%	-0.11%	1.93%	2.34%	0.12%	2.46%
344.00 Generators and Devices	2.51%	-0.13%	2.38%	4.45%	0.22%	4.67%
345.00 Accessory Electric Equipment	2.05%	-0.10%	1.95%	2.41%	0.13%	2.54%
346.00 Miscellaneous Power Plant Equipment	2.49%	-0.12%	2.37%	2.85%	0.15%	3.00%
Total Sun Dance	2.06%	-0.11%	1.95%	2.44%	0.13%	2.57%
West Phoenix						
341.00 Structures and Improvements	3.04%	-0.15%	2.89%	3.39%	0.23%	3.62%
342.00 Fuel Holders, Products and Accessories	3.67%	-0.17%	3.50%	3.81%	0.19%	4.00%
343.00 Prime Movers	2.73%	-0.09%	2.64%	3.64%	0.19%	3.83%
344.00 Generators and Devices	3.33%	-0.36%	2.97%	3.88%	0.03%	3.91%
345.00 Accessory Electric Equipment	3.51%	-0.15%	3.36%	4.53%	0.29%	4.82%
346.00 Miscellaneous Power Plant Equipment	3.80%	-0.17%	3.63%	4.45%	0.23%	4.68%
Total West Phoenix	3.18%	-0.24%	2.94%	3.84%	0.11%	3.95%
West Phoenix CC Units 1-3						
341.00 Structures and Improvements	5.00%	-0.24%	4.76%	4.03%	0.19%	4.22%
342.00 Fuel Holders, Products and Accessories	4.02%	-0.18%	3.84%	3.94%	0.20%	4.14%
343.00 Prime Movers						
344.00 Generators and Devices	4.08%	-0.65%	3.43%	4.00%	0.14%	4.14%
345.00 Accessory Electric Equipment	4.01%	-0.15%	3.86%	5.21%	0.35%	5.56%
346.00 Miscellaneous Power Plant Equipment	4.17%	-0.18%	3.99%	4.82%	0.23%	5.05%
Total West Phoenix CC Units 1-3	4.07%	-0.48%	3.59%	4.21%	0.19%	4.40%
West Phoenix CC Unit 4						
341.00 Structures and Improvements	3.05%	-0.15%	2.90%	3.30%	0.17%	3.47%
342.00 Fuel Holders, Products and Accessories	2.98%	-0.15%	2.83%	3.21%	0.16%	3.37%
343.00 Prime Movers	2.98%	-0.15%	2.83%	3.21%	0.02%	3.23%
344.00 Generators and Devices	3.07%	-0.30%	2.77%	3.80%	0.18%	3.98%
345.00 Accessory Electric Equipment	3.57%	-0.18%	3.39%	4.00%	0.20%	4.20%
346.00 Miscellaneous Power Plant Equipment	3.72%	-0.17%	3.55%	4.50%	0.22%	4.72%
Total West Phoenix CC Unit 4	3.02%	-0.19%	2.83%	3.40%	0.08%	3.48%

ARIZONA PUBLIC SERVICE COMPANY

Statement A

Component Accrual Rates

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Proposed: VG Procedure / RL Technique

Account Description A	Current (at 12/31/2015)			Proposed (at 12/31/2015)		
	Investment B	Net Salvage C	Total D=B+C	Investment E	Net Salvage F	Total G=E+F
West Phoenix CC Unit 5						
341.00 Structures and Improvements	2.92%	-0.15%	2.77%	3.48%	0.18%	3.66%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers	3.01%	-0.08%	2.93%	3.53%	0.20%	3.73%
344.00 Generators and Devices	2.97%	-0.19%	2.78%	3.76%	-0.09%	3.67%
345.00 Accessory Electric Equipment	2.91%	-0.15%	2.76%	3.52%	0.19%	3.71%
346.00 Miscellaneous Power Plant Equipment	3.40%	-0.17%	3.23%	4.12%	0.22%	4.34%
Total West Phoenix CC Unit 5	2.98%	-0.15%	2.83%	3.67%	0.03%	3.70%
West Phoenix CT Units 1-2						
341.00 Structures and Improvements	3.80%	-0.19%	3.61%	6.05%	0.46%	6.51%
342.00 Fuel Holders, Products and Accessories	0.61%	-0.03%	0.58%	3.36%	0.17%	3.53%
343.00 Prime Movers	1.00%	-0.03%	0.97%	5.03%	0.49%	5.52%
344.00 Generators and Devices	2.25%	-0.21%	2.04%	4.80%	0.29%	5.09%
345.00 Accessory Electric Equipment	0.95%	-0.04%	0.91%	2.61%	0.13%	2.74%
346.00 Miscellaneous Power Plant Equipment	3.25%	-0.16%	3.09%	3.52%	0.26%	3.78%
Total West Phoenix CT Units 1-2	1.62%	-0.10%	1.52%	4.86%	0.40%	5.26%
West Phoenix Common						
341.00 Structures and Improvements	2.76%	-0.12%	2.64%	2.44%	0.24%	2.68%
342.00 Fuel Holders, Products and Accessories						
343.00 Prime Movers						
344.00 Generators and Devices						
345.00 Accessory Electric Equipment						
346.00 Miscellaneous Power Plant Equipment						
Total West Phoenix Common	2.76%	-0.12%	2.64%	2.44%	0.24%	2.68%
Yucca						
341.00 Structures and Improvements	2.41%	-0.09%	2.32%	4.70%	0.29%	4.99%
342.00 Fuel Holders, Products and Accessories	0.90%	-0.04%	0.86%	1.86%	0.10%	1.96%
343.00 Prime Movers	2.54%	-0.13%	2.41%	2.98%	0.19%	3.17%
344.00 Generators and Devices	1.29%	-0.24%	1.05%	3.36%	0.21%	3.57%
345.00 Accessory Electric Equipment	1.15%	-0.05%	1.10%	2.94%	0.27%	3.21%
346.00 Miscellaneous Power Plant Equipment	1.82%	-0.09%	1.73%	2.88%	0.15%	3.03%
Total Yucca	2.26%	-0.13%	2.13%	3.06%	0.19%	3.25%
Yucca CT Units 1-4						
341.00 Structures and Improvements	2.29%	-0.08%	2.21%	4.99%	0.31%	5.30%
342.00 Fuel Holders, Products and Accessories	0.11%		0.11%	1.42%	0.08%	1.50%
343.00 Prime Movers	-0.09%		-0.09%	2.80%	0.44%	3.24%
344.00 Generators and Devices	1.27%	-0.24%	1.03%	3.36%	0.21%	3.57%
345.00 Accessory Electric Equipment	0.75%	-0.03%	0.72%	2.84%	0.27%	3.11%
346.00 Miscellaneous Power Plant Equipment	1.11%	-0.06%	1.05%	2.38%	0.12%	2.50%
Total Yucca CT Units 1-4	0.80%	-0.09%	0.71%	3.12%	0.28%	3.40%
Yucca CT Units 5-6						
341.00 Structures and Improvements	2.97%	-0.15%	2.82%	3.29%	0.17%	3.46%
342.00 Fuel Holders, Products and Accessories	2.97%	-0.15%	2.82%	3.01%	0.15%	3.16%
343.00 Prime Movers	2.97%	-0.15%	2.82%	3.01%	0.15%	3.16%
344.00 Generators and Devices	2.97%	-0.15%	2.82%	3.14%	0.16%	3.30%
345.00 Accessory Electric Equipment	2.97%	-0.15%	2.82%	3.41%	0.23%	3.64%
346.00 Miscellaneous Power Plant Equipment	2.97%	-0.15%	2.82%	3.70%	0.19%	3.89%
Total Yucca CT Units 5-6	2.97%	-0.15%	2.82%	3.03%	0.15%	3.18%

Appendix B

Palo Verde Decommissioning Trust Amounts
Test Year Ended 12/31/2015
(Dollars in Thousands)

YEAR	<u>6/1/2045</u> UNIT 1	<u>4/24/2046</u> UNIT 2	<u>11/25/2047</u> UNIT 3	TOTAL ²	ACC Jurisdictional Amount ¹
2016	449	-	1,832	2,281	\$ 2,265
2017	377	868	1,036	2,281	2,265
2018	377	868	1,036	2,281	2,265
2019	377	868	1,036	2,281	2,265
2020	377	868	1,036	2,281	2,265
2021	377	868	1,036	2,281	2,265
2022	377	868	1,036	2,281	2,265
2023	377	868	1,036	2,281	2,265
2024	377	868	1,036	2,281	2,265
2025	377	868	1,036	2,281	2,265
2026	377	868	1,036	2,281	2,265
2027	377	868	1,036	2,281	2,265
2028	377	868	1,036	2,281	2,265
2029	377	868	1,036	2,281	2,265
2030	377	868	1,036	2,281	2,265
2031	377	868	1,036	2,281	2,265
2032	377	868	1,036	2,281	2,265
2033	377	868	1,036	2,281	2,265
2034	377	868	1,036	2,281	2,265
2035	377	868	1,036	2,281	2,265
2036	377	868	1,036	2,281	2,265
2037	377	868	1,036	2,281	2,265
2038	377	868	1,036	2,281	2,265
2039	377	868	1,036	2,281	2,265
2040	377	868	1,036	2,281	2,265
2041	377	868	1,036	2,281	2,265
2042	377	868	1,036	2,281	2,265
2043	377	868	1,036	2,281	2,265
2044	377	868	1,036	2,281	2,265
2045	189	868	1,036	2,092	2,078
2046	-	217	1,036	1,253	1,244
2047	-	-	1,036	1,036	1,028
	\$ 11,207	\$ 25,389	\$ 33,933	\$ 70,528	\$ 70,049

1. ACC Jurisdictional share is approximately 99.32%.

2. Arizona Public Service Company ("APS") is proposing to keep the level of Decommissioning Trust funding constant. Therefore, APS is not proposing any additional funding even though APS anticipates higher amounts than what are reflected in this Schedule.

Appendix C



**Power Supply Adjustment
Plan of Administration**

Table of Contents

1. General Description	1
2. PSA Components	2
3. Calculation of the PSA Rate	4
4. Filing and Procedural Deadlines	5
5. Verification and Audit	5
6. Definitions	6
7. Schedules	8
8. Compliance Reports	8
9. Allowable Costs	10

1. General Description

This document describes the plan for administering the Power Supply Adjustment mechanism ("PSA") approved for Arizona Public Service Company (APS) by the Commission on June 28, 2007 in Decision No. 69663, and subsequently amended by the Commission in Decision Nos. 71448 (December 30, 2009), 73183 (May 24, 2012), and XXXXX (XXX XX, 201X). The PSA provides for the recovery of fuel and purchased power costs and other production-related variable costs to the extent that those costs deviate from the amount recovered through APS's Base PSA Cost (\$0.030667 per kWh) authorized in Decision No. XXXXX, from XXX XX, 201X.

Non-fuel production costs included in the PSA relate to environmental chemical expenses which vary directly with power plant production. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The PSA allows for the refund or recovery of said costs that deviate from the base cost amount of \$0.000500 per kWh¹.

In addition, the PSA allows for the refund or recovery of the net margins from sales of emission allowances, to the extent the actual sales margins deviate from the base cost amount of (\$0.000001) per kWh² and for recovery of mandated carbon emission costs when it is economical to incur those costs as discussed below.

APS shall not incur mandatory carbon emission allowance costs unless it passes those costs on to the California entities that are purchasing energy from APS. In no event shall APS incur California's carbon emission allowance costs when doing so is not an economical choice for APS's Arizona ratepayers.

¹ \$0.000500 per kWh is the result of the following: (2015 chemical costs of \$13,527,111 / 2015 test year native load sales of 27,030,686 MWh) / 1000.

² (\$0.000001) per kWh is the result of the following: (2015 net gains from sales of SO₂ allowances of \$25,181 / 2015 test year native load sales of 27,030,686 MWh) / 1000.



The PSA described in this Plan of Administration ("POA") uses a forward-looking estimate of fuel and purchased power costs and environmental chemical costs for fossil fuel production, and margins on the sales of emission allowances ("PSA Costs") to set a rate that is then reconciled to actual costs experienced.

This PSA includes a limit of \$0.004 per kilowatt-hour (kWh) on the amount the PSA rate may change in any one year absent express approval of the Commission. This PSA also provides a mechanism for mid-year rate adjustment by either the Commission or the Company (only if overcollection) in the event that conditions change sufficiently to cause extraordinarily high balances to accrue under application of this PSA.

2. PSA Components

The PSA Rate will consist of three components designed to provide for the recovery of actual, prudently incurred PSA Costs. Those components are:

1. The Forward Component, which recovers or refunds differences between expected PSA Year's³ PSA Costs and those embedded in base rates.
2. The Historical Component, which tracks the differences between the PSA Year's actual PSA Costs (fuel, purchased power and other allowable costs) and the recovery of those same cost elements through the combination of base rates and the Forward Component, and which provides for their recovery or refund during the next PSA Year.
3. The Transition Component, which provides for:
 - a. The opportunity to seek mid-year changes in the PSA rate in cases where variances between the anticipated recovery of fuel and purchased power and other allowable costs for the PSA Year under the combination of base rates and the Forward Component become so large as to warrant recovery/refund, should the Commission deem such an adjustment to be appropriate or if the Company requests to make such refund of an overcollection.
 - b. The tracking of balances resulting from the application of the Transition Components, in order to provide a basis for the refund or recovery of any such balances.

Except for circumstances when the Commission approves new base rates, a PSA Year begins on February 1 and ends on the ensuing January 31. In the event that new base rates become effective on a date other than February 1, the Commission may, at its discretion, adjust any or all of the PSA components to reflect the new base rates.

On or before November 30 of each year, APS will submit a PSA Rate filing, which shall include a calculation of the three components of the proposed PSA Rate. This filing shall be accompanied by such supporting information as Staff determines to be required.

a. Forward Component Description

The Forward Component is intended to refund or recover the difference between: (1) PSA Costs embedded in base rates and (2) the forecast PSA Costs over a PSA Year that begins on February

³ Each February 1 through January 31 period shall constitute a PSA Year



1 and ends on the ensuing January 31. APS will submit, on or before November 30 of each year, a forecast for the upcoming calendar year (January 1-December 31) of its PSA Costs. It will also submit a forecast of kWh sales for the same calendar year, and divide the forecast costs by the forecast sales to produce the cents/kWh unit rate required to collect those costs over those sales. The result of subtracting the Base PSA Costs from this unit rate shall be the Forward Component.

APS shall maintain and report monthly the balances in a Forward Component Tracking Account, which will record APS's over/under-recovery of its actual PSA Costs as compared to the Base PSA Costs recovered in revenue. The balance calculated as a result of these steps is then reduced by the current month's collection of Forward Component revenue. This account will operate on a PSA Year basis (i.e. February to January), and its balances will be used to administer this PSA's Historical Component, which is described immediately below.

b. Historical Component Description

The Historical Component in any current PSA Year is intended to refund or recover the balances accumulated in the Forward Component Tracking Account (described above) and Historical Component Tracking Account (described below) during the immediately preceding PSA Year. The sum of the projected Forward Component Tracking Account balance on January 31 of the following calendar year and the projected Historical Component Tracking Account balance on January 31 of the following calendar year is divided by the forecast kWh sales used to set the Forward Component for the coming PSA Year. That result comprises the proposed Historical Component for the coming PSA year.

APS shall maintain and report monthly the balances in a Historical Component Tracking Account, which will reflect monthly collections under the Historical Component and the amounts approved for use in calculating the Historical Component.

Each annual November 30 APS filing will include an accumulation of Forward Component Tracking Account balances and Historical Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the current PSA Year). The APS filing shall use these balances to calculate the Historical Component for the coming PSA Year⁴.

The November 30 filing's use of estimated balances for November through January (with supporting workpapers) is required to allow the PSA review process to begin in a way that will support its completion and a Commission decision, if necessary, prior to February 1.

The Historical Component Tracking Account will measure the changes each month in the Historical Component balance used to establish the current Historical Component as a result of collections under the Historical Component in effect. It will subtract each month's Historical Component collections from the Historical Component balance. The Historical Component

⁴ For example, the November 30, 2008 filing would include actual balances for February through October of 2008 and estimated balances for November 2008 through January 2009.



Account will also include Applicable Interest on any balances. APS shall file the amounts and supporting calculations and workpapers for this account each month.

c. Transition Component Description

The Transition Component will be used as the method for incorporating any approved mid-year changes to the PSA rate. APS or Staff may request at any time a change in the PSA rate through an adjustment to the Transition Component to address a significant imbalance between anticipated collections and costs for the PSA Year under the Forward Component element of this PSA. After the review of such request, the Commission may provide for the refund or collection of such balance (through a change to the Transition Component Balance) over such period as the Commission determines appropriate through a unit rate (\$/kWh) imposed as part of the Transition Component. The Commission on its own motion may also change the PSA rate as described above.

Notwithstanding the preceding paragraph, APS may at any time during the PSA Year request to reduce the PSA through the Transition Component, which request shall be deemed approved and become effective beginning with the first billing cycle of the month following the filing of such a request, provided APS files the request within the first 15 days of a month and Staff does not file opposition to the request.

A Transition Component Tracking Account will measure the changes each month in the Transition Component balance. APS, Staff, or the Commission on its own motion may request that the balance in any Transition Component Tracking Account at the end of the period set for recovery be included in the establishment of the Transition Component for the coming PSA Year.

The Transition Component Account will also include Applicable Interest as determined by the Commission. APS shall file the amounts and supporting calculations and workpapers for this account each month.

As it must do for the Historical Component filing, APS shall file on or before November 30 of each year an accumulation of Transition Component Tracking Account balances for the preceding February through October and an estimate of the balances for November through January (the remaining three months of the prior PSA Year). Those balances will form the basis for setting the preliminary Transition Component for the coming PSA Year.

3. Calculation of the PSA Rate

The PSA rate is the sum of the three components; *i.e.*, Forward Component, Historical Component, and Transition Component. The PSA rate shall be applied to customer bills. Unless the Commission has otherwise acted on a new PSA rate by February 1, the proposed PSA rate shall go into effect. However, the PSA rate may not change from the prior year's PSA rate by more than plus or minus \$0.004 per kWh without an offsetting change in the Base Cost of Fuel and Purchased Power. The PSA rate shall be applicable to APS's retail electric rate schedules



(with the exception of E-36 XL, AG-X, Direct Access service and any other rate that is exempt from the PSA) and is adjusted annually. The PSA Rate shall be applied to the customer's bill as a monthly kWh charge that is the same for all customer classes.

The PSA rate shall be reset on February 1 of each year, and shall be effective with the first February billing cycle unless suspended by the Commission. It is not prorated.

4. Filing and Procedural Deadlines

a. November 30 Filing

APS shall file the PSA rate with all Component calculations for the PSA year beginning on the next February 1, including all supporting data, with the Commission on or before November 30 of each year. That calculation shall use a forecast of kWh sales and of PSA Costs for the coming calendar year, with all inputs and assumptions being the most current available for the Forward Component. The filing will also include the Historical Component calculation for the year beginning on the next February 1, with all supporting data. That calculation shall use the same forecast of sales used for the Forward Component calculation. The Transition Component filing shall also include a proposed method for addressing the over or under recovery of any Transition Component balances that result from changes in the sales forecasts or recovery periods set or any additions to or subtractions from Transition Component balances reviewed or approved by the Commission since the last February 1 resetting of the new PSA.⁵

b. Additional Filings

APS shall also file with the Commission any additional information that the Staff determines it requires to verify the component calculations, account balances, and any other matter pertinent to the PSA.

c. Review Process

The Commission Staff and interested parties shall have an opportunity to review the November 30 forecast, balances, and supporting data on which the calculations of the three PSA components have been based. Any objections to the November 30 calculations shall be filed within 60 days of the APS filing. Before Storage Product Costs may be calculated in the PSA, APS will first seek approval. APS will request this approval by filing the third party storage contract with the Commission at least 90 days before the contract becomes effective. Unless the Commission has otherwise acted on the APS calculation by February 1, the PSA rate proposed by APS shall go into effect with the first February billing cycle.

5. Verification and Audit

⁵ This method assumes that the Commission defers the recovery of any approved Transition Component Balance changes until the next February 1 PSA resetting. The Commission may also, as part of the approval of any such Transition Component Balance change, make a PSA change effective on dates and across periods as it determines to be appropriate when it approves such a Transition Component Balance change.



The amounts charged through the PSA shall be subject to periodic audit to assure their completeness and accuracy and to assure that all fuel and purchased power and other allowable costs were incurred reasonably and prudently. The Commission may, after notice and opportunity for hearing, make such adjustments to existing balances or to already recovered amounts as it finds necessary to correct any accounting or calculation errors or to address any costs found to be unreasonable or imprudent. Such adjustments, with appropriate interest, shall be recovered or refunded through the Transition Component.

6. Definitions

Applicable Interest - Interest is applied on the PSA balance annually at the following rates: any over-collection existing at the end of the PSA year will be credited an amount equal to interest at a rate equal to the Company's authorized Return on Equity ("ROE") or APS's then-existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the end of the PSA Year will be debited an amount equal to interest at a rate equal to the Company's authorized ROE or APS's then-existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

Base Chemical Costs - An amount generally expressed as a rate per kWh, which reflects the non-fuel production costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The production-related environmental chemical costs are limited to expenses for lime, sulfur and ammonia used at fossil fuel generation sites. The Base Chemical Costs are set at \$0.000500 per kWh effective on XXX XX, 201X.

Base Cost of Fuel and Purchased Power - An amount generally expressed as a rate per kWh, which reflects the fuel and purchased power costs embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Cost of Fuel and Purchased Power recovered in base revenue is the approved rate per kWh times the applicable sales volumes. Decision No. XXXXX set the base cost at \$0.030168 per kWh effective on XXX XX, 201X.

Base Net Margins on the Sale of Emission Allowances - An amount generally expressed as a rate per kWh, which reflects the net margins on sales of SO₂ emission allowances embedded in the base rates as approved by the Commission in APS's most recent rate case. The Base Net Margins on the Sale of Emission Allowances is set at (\$0.000001) per kWh effective on XXX XX, 201X.

Base PSA Costs - A rate equal to the sum of Base Cost of Fuel and Purchased Power as defined above, the Base Chemical Costs, and the Base Net Margins on the Sale of Emission Allowances.

Forward Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February. The Forward Component for the PSA Year will adjust for the difference between the forecast PSA Costs generally expressed as a rate per kWh less the Base PSA Costs generally expressed as a rate per kWh embedded in APS's base rates. The result of this calculation will equal the Forward Component, generally expressed as a rate per kWh.



Forward Component Tracking Account - An account that records on a monthly basis APS's over/under-recovery of its actual PSA Costs as compared to the actual Base PSA Costs recovered in revenue and Forward Component revenue, plus Applicable Interest. The balance of this account as of the end of each PSA Year is, subject to periodic audit, reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Historical Component - An amount generally expressed as a rate per kWh charge that is updated annually on February 1 of each year and effective with the first billing cycle in February unless suspended by the Commission. The purpose of this charge is to provide for a true-up mechanism to reconcile any over or under-recovered amounts from the preceding PSA Year tracking account balances to be refunded/collected from customers in the coming year's PSA rate.

Historical Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Historical Component rate as compared to the actual Historical Component revenues; plus Applicable Interest at year end. The balance of which at the close of the preceding PSA Year is, subject to periodic audit, then reflected in the next Historical Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

ISFSI - Costs associated with the Independent Spent Fuel Storage Installation that stores spent nuclear fuel.

Mandated Carbon Emission Allowance Costs - The costs incurred in purchasing allowances to meet legal requirements, beginning in 2013, that electricity from resources which emit carbon must be accompanied by carbon emission allowances equal to the amount of carbon emitted in generating the electricity (recorded in FERC Account 509 - Allowances).

Mark-to-Market Accounting - Recording the value of qualifying commodity contracts to reflect their current market value relative to their actual cost.

Native Load - Native load refers to the energy for both customer load in the balancing authority area for which APS has a generation service obligation plus PacifiCorp Supplemental Sales.

Net Margins on the Sale of Emission Allowances - Revenues incurred from the sale of emission allowances net of the costs incurred to produce the excess allowances.

PacifiCorp Supplemental Sales - The PacifiCorp Supplemental Sales agreement is a long-term contract from 1990 which requires APS to offer a certain amount of energy to PacifiCorp each year. It is a component of the set of agreements that led to the sale of Cholla Unit 4 to PacifiCorp and the establishment of the seasonal diversity exchange with PacifiCorp.

Preference Power - Power allocated to APS wholesale customers by federal power agencies such as the Western Area Power Administration.

PSA - The Power Supply Adjustment mechanism approved by the Commission.



PSA Costs - The combination of System Book Fuel and Purchased Power Costs net of the System Book Off-System Sales Revenues plus costs for environmental chemicals used in power production at fossil and nuclear production sites, approved storage product costs, and the Net Margins on the Sales of Emission Allowances.

PSA Year - A consecutive 12-month period generally beginning each February 1.

Rate Schedule AG-X - Alternative Generation Rate Schedule approved by the Commission in Decision No. XXXXX. Resale of capacity and energy displaced by Rate Schedule AG-X shall be excluded from the PSA at a flat amount of \$1,250,000 a month. The portion of capacity and energy sales margins that is not the result of displacement from Rate Schedule AG-X will continue to be a credit to the PSA.

Storage Product Costs - All costs associated with third-party storage facilities, including rent, capacity, and lease payments for electricity storage facilities (e.g. batteries) that APS utilizes in the dispatch of generated or purchased electricity.

System Book Fuel and Purchased Power Costs - The costs recorded for the fuel and purchased power used by APS to serve both Native Load and off-system sales, less the costs associated with applicable special contracts, E-36 XL, AG-X, RCDAC-1, ISFSI, and Mark-to-Market Accounting adjustments. Wheeling costs and broker fees are included up to the level in the Base Cost of Fuel and Purchased Power authorized in Decision No. xxxxx.

System Book Off-System Sales Revenue - The revenue recorded from sales made to non-Native Load customers, for the purpose of optimizing the APS system, using APS-owned or contracted generation and purchased power, less Mark-to-Market Accounting adjustments.

Traditional Sales-for-Resale - The portion of load from Native Load wholesale customers that is served by APS, excluding the load served with Preference Power.

Transition Component - An amount generally expressed as a rate per kWh charge to be applied when necessary to provide for significant changes between estimated and actual costs under the Forward Component.

Transition Component Tracking Account - An account that records on a monthly basis the account balance to be collected via the Transition Component as compared to the actual Transition Component revenues, plus applicable interest; the balance of which upon Commission consideration may then be reflected in the next Transition Component calculation. APS files the balances and supporting details underlying this Account with the Commission on a monthly basis.

Wheeling Costs (FERC Account 565, Transmission of Electricity by Others) - Amounts payable to others for the transmission of APS's electricity over transmission facilities owned by others.

7. Schedules

Samples of the following schedules are attached to this Plan of Administration



Schedule 1	Power Supply Adjustment (PSA) Rate Calculation
Schedule 2	PSA Forward Component Rate Calculation
Schedule 3	PSA Year Forward Component Tracking Account
Schedule 4	PSA Historical Component Rate Calculation
Schedule 5	Historical Component Tracking Account
Schedule 6	PSA Transition Component Rate Calculation
Schedule 7	PSA Transition Tracking Account

8. Compliance Reports

APS shall provide monthly reports to Staff and to the Residential Utility Consumer Office detailing all calculations related to the PSA. An APS Principal Officer, as listed in APS's annual report filed with the Commission's Corporations Division, shall certify under oath that all information provided in the reports itemized below is true and accurate to the best of his or her information and belief. These monthly reports shall be due within 30 days of the end of the reporting period.

The publicly available reports will include at a minimum:

1. The PSA Rate Calculation (Schedule 1); Forward Component, Historical Component, and Transition Component Calculations (Schedules 2, 4, and 6); Annual Forward Component, Historical Component, and Transition Component Tracking Account Balances (Schedules 3, 5, and 7). Additional information will provide other relative inputs and outputs such as:
 - a. Total power and fuel costs.
 - b. Margins on the sale of excess emission allowances.
 - c. Environmental chemical costs for fossil generation.
 - d. Customer sales in both MWh and thousands of dollars by customer class.
 - e. Number of customers by customer class.
 - f. A detailed listing of all items excluded from the PSA calculations.
 - g. A detailed listing of any adjustments to the adjustor reports.
 - h. Total off-system sales revenues.
 - i. System losses in MW and MWh.
 - j. Monthly maximum retail demand in MW.
2. Identification of a contact person and phone number from APS for questions.

APS shall provide to Commission Staff monthly reports containing the information listed below. These reports shall be due within 30 days of the end of the reporting period. All of these additional reports will be provided confidentially.

- A. Information for each generating unit shall include the following items:
1. Net generation, in MWh per month, and 12 months cumulatively.
 2. Average heat rate, both monthly and 12-month average.
 3. Equivalent forced-outage factor, both monthly and 12-month average.



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4. Outage information for each month including, but not limited to, event type, start date and time, end date and time, and a description.
 5. Total fuel costs per month.
 6. The fuel cost per kWh per month.
- B. Information on power purchases shall include the following items per seller (information on economy interchange purchases may be aggregated):
1. The quantity purchased in MWh.
 2. The demand purchased in MW to the extent specified in the contract.
 3. The total cost for demand to the extent specified in the contract.
 4. The total cost of energy.
- C. Information on off-system sales shall include the following items:
1. An itemization of off-system sales margins per buyer.
 2. Details on negative off-system sales margins.
- D. Fuel purchase information shall include the following items:
1. Natural gas interstate pipeline costs, itemized by pipeline and by individual cost components, such as reservation charge, usage, surcharges and fuel.
 2. Natural gas commodity costs, categorized by short-term purchases (one month or less) and longer term purchases, including price per therm or per MCF, total cost, supply basin, and volume by contract.
- E. APS will also provide:
1. Monthly projections for the next 12-month period showing estimated (over)/under-collected amounts.
 2. A summary of unplanned outage costs by resource type.
 3. A summary of the net margins on the sale of emission allowances.
 4. The data necessary to arrive at the System and Off-System Book Fuel and Purchased Power cost reflected in the non-confidential filing.
 5. The data necessary to arrive at the Native Load Energy Sales MWh reflected in the non-confidential filing.

Work papers and other documents that contain proprietary or confidential information will be provided to the Commission Staff under an appropriate confidentiality agreement. APS will keep fuel and purchased power invoices and contracts available for Commission review. The Commission has the right to review the prudence of fuel and power purchases and any calculations associated with the PSA at any time. Any costs flowed through the PSA are subject to refund if those costs are found to be imprudently incurred.

9. Allowable Costs

a. Accounts

The allowable PSA costs include fuel and purchased power costs incurred to provide service to retail customers. And, the prudent direct costs of contracts used for hedging system fuel and purchased power will be recovered under the PSA. Additionally, costs for specified



environmental chemicals that vary with power generated at fossil power plants, storage product costs, and the net margins on the sale of emission allowances and Mandated Carbon Emission Allowance Costs will also be refunded or recovered through the PSA. The allowable cost components include the following Federal Energy Regulatory Commission (FERC) accounts:

- 501 Fuel (Steam)
- 518 Fuel (Nuclear) less ISFSI regulatory amortization
- 547 Fuel (Other Production)
- 555 Purchased Power
- 565 Wheeling (Transmission of Electricity by Others)
- 411 O&M (Margins on the Sale of Emission Allowances)
- 509 Allowances⁶

Additionally, broker fees recorded in FERC account 557 up to the amount included in the Base Fuel Cost, costs for environmental chemicals used in power production in FERC accounts 502 and 549, and the FERC account where applicable Storage Product Costs will be recorded are allowable accounts.

These accounts are subject to change if the Federal Energy Regulatory Commission alters its accounting requirements or definitions.

b. Directly Assignable Power Supply Costs Excluded

Decision No. 66567 provides APS the ability to recover reasonable and prudent costs associated with customers who have left APS standard offer service, including special contract rates, for a competitive generation supplier and then return to standard offer service. For administrative purposes, customers who were direct access customers since origination of service and request standard offer service would be considered to be returning customers. A direct assignment or special adjustment may be applied that recognizes the cost differential between the power purchases needed to accommodate the returning customer and the power supply cost component of the otherwise applicable standard offer service rate. This process is described in the Returning Customer Direct Access Charge rate schedule and associated Plan for Administration filed with the Commission.

In addition, if APS purchases power under specific terms on behalf of a standard offer special contract customer, the costs of that power may be directly assigned. In both cases, where specific power supply costs are identified and directly assigned to a large returning customer or standard offer special contract customer or group of customers, these costs will be excluded from the Adjustor Rate calculations. Schedule E-36 XL and AG-X customers are directly assigned power supply costs based on the APS system incremental cost at the time the customer is consuming power from the APS system so their power supply costs and kWh usage are excluded from the PSA.

⁶ Or any successor FERC account used to record the costs of purchasing carbon emission allowances.

ARIZONA PUBLIC SERVICE COMPANY

Schedule 1

Power Supply Adjustment (PSA) Rate Calculation

(\$/kWh)

Line No.	PSA Rate Calculation	Current February 1, XXXX	Proposed February 1, XXXX ¹	Increase/(Decrease) \$/kWh	%
1	Forward Component Rate - FC (Schedule 2, L16)	\$ -	\$ -	N/A	N/A
2	Historical Component Rate - HC (Schedule 4, L5) ²	# #####	\$ -	N/A	N/A
3	PSA Transition Component Rate (Schedule 6, L3) ³	\$ -	\$ -	N/A	N/A
4	PSA Rate (L1+ L2 + L3)	# #####	\$ -	N/A	N/A

Notes:

¹ Proposed levels of the PSA rate components are provided in the November 30 filing each year.

² A Historical Component is a true up related to respective prior period PSA activity.

³ Provides for Mid-Period Corrections when necessary.

ARIZONA PUBLIC SERVICE COMPANY

Schedule 2

PSA Forward Component Rate Calculation

(\$ in thousands; Forward Component Rate in \$/kWh)

Line No.		Current February 1, XXXX ¹	Proposed February 1, XXXX ¹	Increase/(Decrease) \$ Values %
PSA Forward Component Rate - Calculation				
1	Projected Fuel and Purchased Power Costs	\$ #,###,###	\$ -	N/A N/A
2	Projected Off-System Sales Revenue	\$ #,###,###	-	N/A N/A
3	PSA Adjustments to Fuel and Purchased Power Costs ²	\$ (#,###,###)	-	N/A N/A
4	Net Fuel and Purchased Power Cost (L1 through L3)	\$ #,###,###	\$ -	N/A N/A
5	Projected Fossil Chemical Costs	-	-	N/A N/A
6	Projected Net Margins on the Sale of Emission Allowances	-	-	N/A N/A
7	Projected Billed Native Load Sales, excluding E-36XL and AG-X (MWh) ³	##,###,###	-	N/A N/A
8	Projected Average Net Fuel Cost \$/kWh (L4 / L7)	#####	\$ -	N/A N/A
9	Average Fossil Chemical Costs \$/kWh (L5 / L7)	#####	-	N/A N/A
10	Projected Average Margin on Emission Allowances \$/kWh (L6 / L7)	\$ -	\$ -	N/A N/A
11	Total Projected Average PSA Cost \$/kWh (L8+L9+L10)	#####	\$ -	N/A N/A
12	Authorized Base Cost of Fuel and Purchased Power Rate \$/kWh ⁴	\$ #,#####	\$ -	N/A N/A
13	Authorized Base Chemical Cost Rate \$/kWh ⁴	#####	-	N/A N/A
14	Authorized Base Net Margins on the Sale of Emission Allowances Rate \$/kWh ⁴	\$ #,#####	\$ -	N/A N/A
15	Total Authorized Base Cost \$/kWh	#####	\$ -	N/A N/A
16	Forward Component Rate \$/kWh (L11 - L15)	#####	\$ -	N/A N/A

Notes:

¹ Proposed levels are provided in the November 30 filing each year.

² Includes costs associated with E-36XL, AG-X and other direct assignment customers, ISFSI, and mark-to-market accounting adjustments.

³ The Projected Billed Native Load Sales of X,XXX,XXX MWh for the Current Rate represent forecast sales for XXXX as of November 30th, XXXX. They exclude sales made under the City of Williams wholesale contract through December 2017.

⁴ Base Cost of Fuel and Purchased Power, Chemicals, and Net Margins on the Sale of Emission Allowances established in Decision No. XXXXX.

Schedule presentation will appear to round up to \$000s and MWh; however, calculations are performed on an actual \$ and kWh basis with resultant Rates/kWh rounded up to \$0.000000/kWh

ARIZONA PUBLIC SERVICE COMPANY

Schedule 3
XXXX PSA Year Forward Component Tracking Account - In Effect from February 1, XXXX to Jan 31, XXXX
(\$ in thousands; Forward Component Rate and Base Rate in \$/kWh)

	Feb-XX	Mar-XX	Apr-XX	May-XX	Jun-XX	Jul-XX	Aug-XX	Sept-XX	Oct-XX	Nov-XX	Dec-XX	Jan-XX	XXXX Total
1 Prior Month's Balance	From L27												
Energy Sales													
2 PSA Retail Energy Sales ¹													
3 Wholesale Native Load Energy Sales ²													
4 Total Native Load Energy Sales													
5 Retail Energy Sales as a % of Total													
6 Retail Billed Sales Excluding E-36XL and AG-X Sales (MWh) ³													
PSA Costs													
7 Fuel and Purchased Power Costs ^{4,5}													
8 Off System Revenue (Credit) ⁶													
9 Off System Margin Displaced by AG-X (Debit)													
10 Fossil Chemical Costs													
11 Net Margins on Sale of Emission Allowances													
12 Net PSA Costs													
Retail PSA Costs													
13 Fuel and Purchased Power Costs													
14 Off System Revenue (Credit)													
15 Off System Margin Displaced by AG-X (Debit)													
16 Fossil Chemical Costs													
17 Net Margins on Sale of Emission Allowances													
18 Net Retail PSA Costs													
Base Rate Power Supply Recovery													
19 Fuel and Purchased Power Recovery													
20 Fossil Chemical Cost Recovery													
21 Net Margins on Sale of Emission Allowances Recovery													
(Over) Under Recovery From Base Rate													
22 Fuel and Purchased Power (Over) Under Recovery													
23 Fossil Chemical Costs (Over) Under Recovery													
24 Net Margins on Sale of Emission Allowances (Over) Under Recovery													
25 Total (Over) Under Recovery													
26 Forward Component Collections ⁷													
27 Tracking Account Balance													
28 Annual Interest (Calculated only in January)													

Notes

- 29 Total Base Fuel Rate - \$ per kWh
- 30 Base Chemical Rate - \$ per kWh
- 31 Base Net Margin on the Sale of Emission Allowances - \$ per kWh
- 32 Forward Component Rate - \$ per kWh
- 1 PSA Retail Energy Sales are the calendar month's MWh sales. XXXX PSA Year Cumulative Retail Energy Sales of XX,XXX MWhs under rate schedules E-36XL and AG-X are excluded from the PSA Calculations
- 2 Includes traditional sales for resale, PacifiCorp supplemental sales, and other non-ACC jurisdictional sales. City of Williams energy sales through December 2017 are excluded from the PSA Calculation
- 3 Retail Billed Sales on Line 6 relate specifically to the Forward Component Collections. Due to billing adjustments and timing, this amount may differ from other components' Retail Billed Sales
- 4 Renewables costs exclude \$X,XXX,XXX of XXXX PSA Year year-to-date costs that are currently being recovered through the REAC rate schedule
- 5 Includes native load and off-system fuel and purchased power costs less those costs associated with E-36XL, AG-X and other direct assignment customers, amortization of previously deferred ISFSI, coal reclamation, and mark-to-market accounting adjustments
- 6 Includes off-system revenue less mark-to-market accounting adjustments
- 7 Generally, Line 6 = Line 26; however, differences may occur due to billing adjustments

ARIZONA PUBLIC UTILITIES COMPANY

Schedule 4

PSA Historical Component Rate Calculation

(\$ in thousands; Historical Component Rate in \$/kWh)

Line No.	PSA Historical Component Rate Calculation	Current February 1, XXXX #,###	Proposed February 1, XXXX ¹ \$	Increase/(Decrease)	
				\$ Values	%
1	Forward Component Tracking Account Balance (Schedule 3, L27 + L28)	-	-	N/A	N/A
2	Historical Component Tracking Account Balance (Schedule 5, L9 + L10) ²	###	-	N/A	N/A
3	Total Historical Amount to be (Refunded)/Collected Balance (L1+L2)	###	\$ -	N/A	N/A
4	Projected Billed Retail Energy Sales without E-36 XL and AG-X (MWh)	###,###,###	-	N/A	N/A
5	Applicable Historical Component Rate (L3 / L4)	#####	\$ -	N/A	N/A

Notes:

¹ Proposed levels are provided in the November 30 filing each year.² The Current Rate Projected Billed Retail Energy Sales are for February XXXX through January XXXX.Schedule presentation will appear to round up to \$000s; however, calculations are performed on an actual \$ and kWh basis with resultant Rates/kWh rounded up to \$0.000000/kWh.

ARIZONA PUBLIC SERVICE COMPANY

Schedule 5

Historical Component Tracking Account in Effect Feb 1, XXXX through Jan. 31, XXXX

(\$ in thousands Historical Component Rate in \$/KWh)

Line No.	January	February	March	April	May	June	XXXX Data July	August	September	October	November	December	XXXX January
1	Projected HC Tracking Account Balance at Nov. 30, XXXX												
2	Projected FC Tracking Account Balance at Nov. 30, XXXX												
3	True-up from November - January Estimate ¹												
4	Prior Month's Ending Balance												
5	HC Adjusted Beginning Balance (L1 + L2 + L3 + L4)												
6	Applicable Historical Component Rate (\$/KWh) ²												
7	Retail Billed Sales Excluding E-36XL and AG-X Sales (MWhs) ³												
8	Less Revenue from Applicable HC (L5 x L7) ⁴												
9	HC Ending Balance (L5 - L8)												
10	Annual Interest (Calculated only in January)												
	\$ -												

Notes:

- ¹ True-up is the result of using estimated revenue and deferral for November, December and January since the actual amount was not available at the time of the projected PSA rate filing.
- ² Historical Component, Schedule 4, Line 5
- ³ Sales amounts are for energy billed each period.
- ⁴ Generally, Line 7 x Line 6 = Line 8; however, differences may occur due to billing adjustments.

Schedule presentation will appear to round up to \$000s and MWh, however, calculations are performed on an actual \$ and KWh basis with resultant Rates/KWh rounded up to \$0.000000/KWh.

ARIZONA PUBLIC UTILITIES COMPANY
Schedule 6

PSA Transition Component Rate Calculation

(\$ in thousands; Transition Component Rate(s) in \$/kWh)

Line No.		Current February 1, XXXX	Proposed February 1, XXXX	Increase/(Decrease)	
				\$ Values	%
1	PSA Transition - Approved (Refundable)/Collection Amount ¹	N/A	N/A	N/A	0.00%
2	Projected Energy Sales without E-36XL and AG-X (MWh) XXX. X, XX to XXX. X,XX	N/A	N/A	N/A	0.00%
3	PSA Transition Component (Refundable)/Collection Rate (L1 / L2)	N/A	N/A	N/A	0.00%

Notes:

¹ Commission Decision No. XXXXXXXXXXXX

Schedule presentation will appear to round up to \$000s and MWh; however, calculations are performed on an actual \$ and kWh basis with resultant Rates/kWh rounded up to \$0.000000/kWh.

ARIZONA PUBLIC SERVICE COMPANY

Schedule 7

PSA Transition Tracking Account in Effect XX 1, 20XX through XX 31, 20XX

(\$ in thousands; Transition Component Rate in \$/kWh)

Line No.		20XX Data												20XX	
		January	February	March	April	May	June	July	August	September	October	November	December	January	January
1	Transferred balance from F.C. Tracking Acct Per Decision No. XXXXX														
2	Prior Month's Ending Balance	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
3	Transition Component TA Adjusted Beginning Balance (L1+ L2)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
4	Applicable Transition TA Component Rate (\$/kWh) ¹	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5	Retail Billed Sales Excluding E-36XL and AG-X Sales (MWhs) ²														
6	Less Revenue from Applicable Transition Component (L4 x L5) ³	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
7	Ending Balance; (L3 - L6)	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -

Notes:

- ¹ Transition Component, Schedule 6, Line 3
² Sales amounts are for energy billed each period.
³ Generally, Line 4 x Line 5 = Line 6; however, differences may occur due to billing adjustments.

Schedule presentation will appear to round up to \$000s and MWh; however, calculations are performed on an actual \$ and kWh basis with resultant Rates/kWh rounded up to \$0.000000/kWh.

ARIZONA PUBLIC VICE COMPANY
Schedule 8
Summary of Monthly Calculations
Mo YYYY
(\$ in thousands)

Line No.	January	February	March	April	May	June	July	August	September	October	November	December	XXXX January
XXXX Data													
XXXX Forward Component Tracking Account													
1	Beginning Balance												
2	Transfers to XXXX Historical Component Tracking Account												
3	Transfers to XXXX Transition Component Tracking Account												
4	(Over)/Under Collection												
5	Less Revenue from Applicable Forward Component Rate												
6	Annual Interest (Calculated only in January)												
7	Ending Balance (Line 1 + Line 2 + Line 3 + Line 4 - Line 5 + Line 6)												
XXXX Historical Component Tracking Account													
8	Beginning Balance												
9	Transfers from XXXX Forward Component Tracking Account												
10	Less Revenue from Applicable Historical Component Rate												
11	Annual Interest (Calculated only in January)												
12	Ending Balance (Line 8 + Line 9 - Line 10 + Line 11)												
XXXX Transition Component Tracking Account													
13	Beginning Balance												
14	Transfers from XXXX Forward Component Tracking Account												
15	Less Revenue from Applicable Historical Component Rate												
16	Annual Interest (Calculated only in January)												
17	Ending Balance (Line 13 + Line 14 - Line 15 + Line 16)												
18	Combined Balance ((Line 7 + Line 12 + Line 17)) ¹												
19	Annual Interest Rate												
	# ##%												

Schedule presentation will appear to round up to \$000s and MWh; however, calculations are performed on an actual \$ and kWh basis with resultant Rates/kWh rounded up to \$0.000000/kWh.

¹ Interest is applied on the PSA balance annually at the following rates: any over-collection existing at the end of the PSA Year will accrue interest at a rate equal to the Company's authorized ROE or APS's existing short term borrowing rate, whichever is greater, and will be refunded to customers over the following 12 months; any under-collection existing at the end of the PSA Year will accrue interest at a rate equal to the Company's authorized ROE or APS's existing short term borrowing rate, whichever is less, and will be recovered from customers over the following 12 months.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 9
YYYY Native Load Customer Counts, Sales and Revenue
Mo YYYY

Line No.	Class	January	February	March	April	May	June	July	August	September	October	November	December	Total ¹
Customers														
1	Residential													#DIV/0!
2	Commercial													#DIV/0!
3	Industrial													#DIV/0!
4	Irrigation													#DIV/0!
5	Sales for Resale ²													#DIV/0!
6	Streetslights & Other Public Authority													#DIV/0!
7	Less E-36XL, AG-X and CoW (includes adj. to prior mth)													#DIV/0!
8	Total													#DIV/0!
Sales (MWh)														
9	Residential													-
10	Commercial													-
11	Industrial													-
12	Irrigation													-
13	Sales for Resale ²													-
14	Streetslights & Other Public Authority													-
15	Less E-36XL, AG-X and CoW (includes adj. to prior mth)													-
16	Total													-
Revenue (\$000)														
17	Commercial													\$ -
18	Industrial													\$ -
19	Irrigation													\$ -
20	Sales for Resale ²													\$ -
21	Streetslights & Other Public Authority													\$ -
22	Less E-36XL, AG-X and CoW (includes adj. to prior mth)													\$ -
23	Total													\$ -
24	Total													\$ -
Est. System Losses and Peak														
25	Est. Native Load Sys. Losses (MWh)													
26	Est. Native Load Sys. Losses (MW)													
27	Est. Native Load Sys. Peak (MW) ³													

¹ The Customers total is the average of the customer class' monthly totals.

² Includes traditional sales for resale, PacifiCorp supplemental sales, City of Williams (CoW), and other non-ACC jurisdictional sales. Off-System Interchange customers, sales and revenue are excluded from Sales for Resale.

³ The Preliminary Native Load System Peak totals will be updated each month.

Appendix D

Transfer of Adjustors into Base Rates

\$ in Millions

	\$	%
Transmission Cost Adjustor Transfer	\$ 128.785	4.46%
Lost Fixed Cost Recovery Adjustor Transfer	46.054	1.59%
Environmental Improvement Surcharge Transfer	2.459	0.09%
Demand Side Management Adjustment Clause Transfer	9.993	0.35%
Renewable Energy Adjustment Clause Transfer	37.596	1.30%
Four Corners Rate Rider Transfer	57.670	2.00%
System Benefits Charge Transfer	(14.604)	-0.51%
Total Surcharge Transfer	\$ 267.953	9.28%

Appendix E



PLAN OF ADMINISTRATION
TAX EXPENSE ADJUSTOR MECHANISM

**Tax Expense Adjustor Mechanism
Plan of Administration**

Table of Contents

1. General Description.....	1
2. Definitions.....	1
3. Calculation of TEAM.....	2
4. TEAM Balancing Account.....	2
5. Filing and Procedural Deadlines	3
6. Compliance Reports.....	3

1. General Description

This document describes the plan for administering the Federal Income Tax Expense Adjustor Mechanism (TEAM) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on [insert date] in Decision No. XXXXX. In the event that significant Federal income tax reform legislation is enacted and effective prior to the conclusion of APS's next General Rate Case (GRC), and such legislation materially impacts¹ the Company's annual revenue requirements; the TEAM enables the pass-through of these income tax effects to customers. The TEAM will be calculated upon the effective date of legislation, and annually on a prospective basis, and will terminate upon the conclusion of APS's next GRC.

2. Definitions

Annual Tax Expense Adjustment – The Annual Tax Expense Adjustment represents the amount to be passed through to jurisdictional retail customers in the subsequent twelve month period and is applied to customer bills via a \$ per kWh adjustment.

Base Revenue Requirements Change – The change in the Company's Base Revenue Requirements as a result of any Federal income tax reform legislation will be measured as the change in:

- The Federal Income Tax Rate-Test Year as compared to the Federal Income Tax Rate-Revised as applied to the Company's Adjusted 2015 Test Year,
- Annual amortization of any resulting excess deferred income tax regulatory account compared to the Company's Adjusted 2015 Test Year, and;
- Permanent income tax adjustments (such as interest expense and/or property tax expense deductibility) compared to those taken in the Company's Adjusted 2015 Test Year.

¹ "Material impacts" is defined as changing APS's revenue requirement by more than \$5 million.



**PLAN OF ADMINISTRATION
TAX EXPENSE ADJUSTOR MECHANISM**

Federal Income Tax Rate-Revised – The Federal income tax rate that is revised as a result of any Federal income tax reform legislation enacted and effective subsequent to Decision No. XXXXX and prior to the conclusion of APS's next GRC.

Federal Income Tax Rate-Test Year – The Federal income tax rate of 35% in effect and utilized in the 2015 Test Year as approved by the Commission in Decision No. XXXXX.

Forecasted Retail kWh Sales – The forecasted calendar year energy (kWh) sales served under applicable ACC jurisdictional retail electric rate schedules. A true-up reconciliation of the forecasted data will be completed in the following year through the Balancing Account.

3. Calculation of TEAM

The Annual Tax Expense Adjustment is calculated annually and represents the amount to be passed through to jurisdictional retail customers. The adjustment is calculated based on the Company's Base Revenue Requirements Change resulting from any Federal income tax reform legislation enacted and effective subsequent to that used to set rates as approved in Decision No. XXXXX, and prior to the conclusion of APS's next GRC, as defined above.

The Annual Tax Expense Adjustment will be applied to applicable customers' total bill via a \$ per kWh adjustment over the twelve month period beginning March 1 of the year following the rate filing described in Section 5 below. The TEAM \$ per kWh rate is calculated by dividing the Annual Tax Expense Adjustment by the Forecasted Retail kWh Sales as determined in Schedule 1 of the filing.

4. TEAM Balancing Account

APS will maintain accounting records that accumulate the difference between the calculated Annual Tax Expense Adjustment as compared to the actual amounts applied to customers' total bills through the TEAM \$ per kWh adjustment during the pass-through period (March through February). Additionally, as a result of utilizing Forecasted Retail kWh Sales, the balancing account will contain a true-up component in which estimated balances will be replaced with actual balances for the prior year filing.

The difference will be recorded to the TEAM Balancing Account each month and will accrue interest at the Company's applicable cost of short-term debt. In the event that the Annual Tax Expense Adjustment is more or less than the amount passed through to customers as of the last billing cycle of February, the over or under collection, plus interest, will be subtracted from or added to the TEAM calculation in the subsequent period.



**PLAN OF ADMINISTRATION
TAX EXPENSE ADJUSTOR MECHANISM**

5. Filing and Procedural Deadlines

APS will file the Annual Tax Expense Adjustment, including all Compliance Reports, with the Commission for the upcoming year by December 1st, terminating at the conclusion of APS's next GRC.

The Commission Staff and interested parties will have the opportunity to review the TEAM filing and supporting data in the adjustor calculation. Unless the Commission has otherwise acted or Staff has filed an objection by March 1st, the new TEAM \$ per kWh rate proposed by APS will go into effect with the first billing cycle in March (without proration) and will remain in effect for the following 12-month period.

6. Compliance Reports

APS will provide an annual report to Staff and the Residential Utility Consumer Office detailing all calculations related to the TEAM \$ per kWh adjustment. The reports will include the following Schedules 1 through 3 as attached to this document:

Schedule 1:	Current Year Annual Tax Expense Adjustment and TEAM \$ per kWh Credit
Schedule 2:	Current Year TEAM Balancing Account
Schedule 3:	Adjusted 2015 Test Year SFR Schedules (as follows):
Schedule 3-A1:	Computation of Increase in Gross Revenue Requirements
Schedule 3-B1(1):	Summary of Original Cost Rate Base Elements
Schedule 3-B1(2):	Summary of RCND Rate Base Elements
Schedule 3-B2:	Original Cost Rate Base Pro Forma Adjustments
Schedule 3-B3:	RCND Rate Base Pro Forma Adjustments
Schedule 3-C1(1):	Total Company Adjusted Test Year Income Statement
Schedule 3-C1(2):	ACC Jurisdiction Adjusted Test Year Income Statement
Schedule 3-C2:	Income Statement Pro Forma Adjustments
Schedule 3-C3:	Computation of Gross Revenue Conversion Factor
Schedule 3-C2 Detail:	Detail of Pro Forma Adjustments as Shown on Schedule 3-C2

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1 - TEAM

ANNUAL TAX ADJUSTMENT AND TEAM \$ PER KWH CREDIT FOR [YEAR]
CURRENT YEAR ENDED 12/31/XXXX
(Thousands of Dollars)

Line No.	(A) Annual Tax Adjustment and TEAM \$ per kWh Credit for [Year]	(B) Reference	(C) \$
1.	Annual Tax Adjustment for [Year]	Schedule 3, A-1, Line 10	
2.	Total TEAM Balancing Account	Schedule 2, Line 4	
3.	Total Annual Tax Adjustment for [Year]	Line 1 + Line 2	
4.	Forecasted Retail Sales (kWh)	Company Records	
5.	Annual TEAM \$/kWh Credit	Line 3 / Line 4	

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY

Schedule 2 - TEAM

TEAM BALANCING ACCOUNT

CURRENT YEAR ENDED 12/31/XXXX

(Thousands of Dollars)

Line No.	(A) Current Year TEAM Balancing Account	(B) Reference	(C) \$
1.	Prior Period Annual Tax Adjustment	Previous Filing Schedule 1, Line 3	
2.	True-up from January-December Estimate (a)	Update Previous Filing Company Records	
3.	Amount Applied to Customer's Bills in Prior Period (b)	Line 1 + Line 2 - Line 3	
4.	TEAM Balancing Account		

(a) Represents any difference between estimated prior period annual tax adjustment filed December 1, 20XX and actual annual tax adjustment based on final December 31, 20XX data.

(b) Represents the amount applied to customers for the twelve (12) calendar months of 20XX. True-up is the result of utilizing forecasted jurisdictional retail sales for the period January through December since the actual sales were not available at the time of prior period filing.

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY**Schedule 3-A1 - TEAM****COMPUTATION OF INCREASE IN GROSS REVENUE REQUIREMENTS**

ACC JURISDICTION

ADJUSTED TEST YEAR ENDED 12/31/2015

(Thousands of Dollars)

Line No.	Description	Electric		Fair Value (C)
		Original Cost (A)	RCND (B)	
1.	Adjusted Rate Base			
2.	Adjusted Operating Income			
3.	Current Rate of Return			
4.	Required Operating Income			
5.	Required Rate of Return on OCRB			
6.	Adjusted Operating Income Deficiency on OCRB			
7.	Gross Revenue Conversion Factor			
8.	Increase/(Decrease) in Base Revenue Requirements Based on OCRB			
9.	After Tax Return on Fair Value Increment			
10.	Requested Increase/(Decrease) in Base Revenue Requirements			

(A) Source: Schedule 3-B1 (1) (F)

(B) Source: Schedule 3-B1 (2) (F)

(C) Calculation

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY

Schedule 3-B1 (1) - TEAM

SUMMARY OF ORIGINAL COST RATE BASE ELEMENTS

TOTAL COMPANY AND ACC JURISDICTION

TEST YEAR ENDED 12/31/2015

(Dollars in Thousands)

Line No.	Description	Original Cost					Line No.	
		Total Company		ACC				
		Settlement (A)	TEAM Pro Formas (B)	Adjusted Settlement (C)=(A)+(B)	Settlement (D)	TEAM Pro Formas (E)		Adjusted Settlement (F)=(D)+(E)
1.	Gross utility plant in service							1.
2.	Less: Accumulated depreciation & amortization							2.
3.	Net utility plant in service							3.
Deductions:								
4.	Deferred income taxes							4.
5.	Investment tax credits							5.
6.	Customer advances for construction							6.
7.	Customer deposits							7.
8.	Pension liabilities							8.
9.	Liability for asset retirements							9.
10.	Other deferred credits							10.
11.	Coal mine reclamation							11.
12.	Unrecognized tax benefits							12.
13.	Regulatory liabilities							13.
14.	Total deductions							14.
Additions:								
15.	Regulatory assets							15.
16.	Other deferred debits							16.
17.	Decommissioning trust accounts							17.
18.	OPEB assets							18.
19.	Allowance for working capital							19.
20.	Total additions							20.
21.	Total rate base							(e) 21.

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY

Schedule 3-B1 (2) - TEAM

SUMMARY OF RCND RATE BASE ELEMENTS

TOTAL COMPANY AND ACC JURISDICTION

TEST YEAR ENDED 12/31/2015

(Dollars in Thousands)

Line No.	Description	RCND				Line No.		
		Total Company		ACC				
		Settlement (A)	TEAM Pro Formas (B)	Adjusted Settlement (C)=(A)+(B)	Settlement (D)		TEAM Pro Formas (E)	Adjusted Settlement (F)=(D)+(E)
1.	Gross utility plant in service							1.
2.	Less: Accumulated depreciation & amortization							2.
3.	Net utility plant in service							3.
4.	Deductions:							4.
5.	Deferred income taxes							5.
6.	Investment tax credits							6.
7.	Customer advances for construction							7.
8.	Customer deposits							8.
9.	Pension liabilities							9.
10.	Liability for asset retirements							10.
11.	Other deferred credits							11.
12.	Coal mine reclamation							12.
13.	Unrecognized tax benefits							13.
14.	Regulatory liabilities							14.
15.	Total deductions							15.
16.	Additions:							16.
17.	Regulatory assets							17.
18.	Other deferred debits							18.
19.	Decommissioning trust accounts							19.
20.	OPEB assets							20.
21.	Allowance for working capital							21.
22.	Total additions							22.
23.	Total rate base							23.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-B2 - TEAM
ORIGINAL COST RATE BASE PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

Line No.	Description	Settlement Test Year 12/31/2015		TEAM ADIT & Regulatory Account Impact		Adjusted Settlement at End of Test Year 12/31/2015	
		Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)=(A)+(C)	ACC (F)=(B)+(D)
1.	Gross Utility Plant in Service						
2.	Less: Accumulated Depreciation & Amort.						
3.	Net Utility Plant in Service						
4.	Less: Total Deductions						
5.	Total Additions						
6.	Total Rate Base						

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-B3 - TEAM
 RCND RATE BASE PRO FORMA ADJUSTMENTS
 TEST YEAR ENDED 12/31/2015
 (Dollars in Thousands)

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

Line No.	Description	Settlement Test Year 12/31/2015		TEAM ADIT & Regulatory Account Impact		Adjusted Settlement at End of Test Year 12/31/2015	
		Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)=(A)+(C)	ACC (F)=(B)+(D)
1.	Gross Utility Plant in Service						
2.	Less: Accumulated Depreciation & Amort.						
3.	Net Utility Plant in Service						
4.	Less: Total Deductions						
5.	Total Additions						
6.	Total Rate Base						

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C1 (1) - TEAM
TOTAL COMPANY
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

<u>Line No.</u>	<u>Description</u>	<u>Total Company</u>			<u>Line No.</u>
		<u>Settlement Test Year Ended 12/31/2015 (A)</u>	<u>TEAM Proforma Adjustments (B)</u>	<u>Settlement Results After Proforma Adjustments (C)=(A)+(B)</u>	
	Electric Operating Revenues				
1.	Revenues from Base Rates				1.
2.	Revenues from Surcharges				2.
3.	Other Electric Revenues				3.
4.	Total				4.
	Operating expenses:				
5.	Electric fuel and purchased power				5.
6.	Operations and maintenance excluding fuel expenses				6.
7.	Depreciation and amortization				7.
8.	Income taxes				8.
9.	Other taxes				9.
10.	Total				10.
11.	Operating income				11.
	Other income (deductions):				
12.	Income taxes				12.
13.	Allowance for equity funds used during construction				13.
14.	Other income				14.
15.	Other expense				15.
16.	Total				16.
17.	Income before interest deductions				17.
	Interest deductions:				
18.	Interest on long-term debt				18.
19.	Interest on short-term borrowings				19.
20.	Debt discount, premium and expense				20.
21.	Allowance for borrowed funds used during construction				21.
22.	Total				22.
23.	Net income				23.

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C1 (2) - TEAM
ACC JURISDICTION
ADJUSTED TEST YEAR INCOME STATEMENT
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Line No.	Description	ACC Jurisdiction			Line No.
		Settlement Test Year Ended 12/31/2015 (A)	TEAM Proforma Adjustments (B)	Settlement Results After Proforma Adjustments (C)=(A)+(B)	
	Electric Operating Revenues				
1.	Revenues from Base Rates				1.
2.	Revenues from Surcharges				2.
3.	Other Electric Revenues				3.
4.	Total				4.
	Operating expenses:				
5.	Electric fuel and purchased power				5.
6.	Operations and maintenance excluding fuel expenses				6.
7.	Depreciation and amortization				7.
8.	Income taxes				8.
9.	Other taxes				9.
10.	Total				10.
11.	Operating income				11.
	Other income (deductions):				
12.	Income taxes				12.
13.	Allowance for equity funds used during construction				13.
14.	Other income				14.
15.	Other expense				15.
16.	Total				16.
17.	Income before interest deductions				17.
	Interest deductions:				
18.	Interest on long-term debt				18.
19.	Interest on short-term borrowings				19.
20.	Debt discount, premium and expense				20.
21.	Allowance for borrowed funds used during construction				21.
22.	Total				22.
23.	Net income				23.

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C2 - TEAM
INCOME STATEMENT PRO FORMA ADJUSTMENTS
TEST YEAR ENDED 12/31/2015
(Dollars in Thousands)

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

Line No.	Description	Normalize Income Tax Expense/Interest Synchronization		Interest Expense on Rate Base Impact		Total Income Tax Income Statement Adjustments	
		Total Co. (A)	ACC (B)	Total Co. (C)	ACC (D)	Total Co. (E)=(A)+(C)	ACC (F)=(B)+(D)
1.	Electric Operating Revenues						
2.	Revenues from Base Rates						
3.	Revenues from Surcharges						
4.	Other Electric Revenues						
	Total Electric Operating Revenues						
5.	Electric Fuel and Purchased Power Costs						
6.	Oper Rev Less Fuel & Purch Pwr Costs						
7.	Other Operating Expenses:						
8.	Operations Excluding Fuel Expense						
9.	Maintenance						
	Subtotal						
10.	Depreciation and Amortization						
11.	Amortization of Gain						
12.	Administrative and General						
13.	Other Taxes						
14.	Total Other Operating Expense						
15.	Operating Income Before Income Tax						
16.	Interest Expense						
17.	Taxable Income						
18.	Current Income Tax Rate -						
19.	Operating Income (line 15 minus line 18)						

(A) Source: Schedule 3-C2 Workpaper Detail

Due to the confidential nature of the financial information contained in this form the future filings will be confidential

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C3 - TEAM
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR
TEST YEAR ENDED 12/31/2015

		Settlement	TEAM Pro Forma
Line No.	Description	Percentage of Incremental Gross Revenues (A)	Percentage of Incremental Gross Revenues (B)
1	Gross Revenue		
2	Less uncollectible revenue		
3	Taxable revenue as a percent		
4	Federal Income Taxes		
5	State Income Taxes Net of Federal Tax Benefit		
6	Total Tax Percentage		
7	Taxable Revenue - Tax Percentage		
8	1/Operating Income % = Gross Revenue Conversion Factor		

'Due to the confidential nature of the financial information contained in this form the future filings will be confidential'

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3-C2 Workpaper Detail - TEAM

TOTAL COMPANY

DETAIL OF PRO FORMA ADJUSTMENTS AS SHOWN ON SCHEDULE 3-C2

TEST YEAR ENDED 12/31/15

(Thousands of Dollars)

Line No.	Description	TEAM Pro Forma (A)	Settlement Test Year (B)
1.	Pre-Tax Operating Income (SFR Schedule C-1, line 11 + line 8)		
2.	Allocated Interest Expense (unadjusted rate base SFR B-1 line 21 * cost of debt SFR D-1 line 1)		
3.	Adjusted Operating Income		
4.	Gross Income Tax at 38.10% (Settlement Test Year) and XX.XX% (TEAM Pro Forma)		
5.	Tax Effected Permanent Items		
6.	Meals and Entertainment		
7.	Non-Deductible Compensation		
8.	Research & Development Credit		
9.	Amortization of OPEB Subsidy PPACA		
10.	Other Federal Tax Credits (Net)		
11.	Amortization of FAS109 Liability		
12.	Arizona Tax Credits		
13.	Depreciation on AFUDC		
14.	Amortization of Permanent Plant Basis Differences		
15a.	New Permanent Income Tax Adjustment [1]		
15b.	New Permanent Income Tax Adjustment [2]		
15c.	Other New Permanent Income Tax Adjustment (Add row as necessary)		
16.	Out of Period Adjustments		
	Rounding		
17.	Net On-Going Tax Expense	-	-
18.	Settlement Test Year Tax Expense (SFR Schedule C-1, line 8)	-	
19.	TEAM Pro Forma Adjustment	<u>\$ -</u>	

(A) Source: 2015 Test Year Normalize Income Tax Expense/Interest Synchronization pro forma, adjusted for tax reform impacts

Appendix F



**RATE SCHEDULE R-XS
EXTRA SMALL RESIDENTIAL SERVICE**

AVAILABILITY

This rate schedule is available to full requirements residential Customers with an average monthly energy usage of 600 kilowatt-hours (kWh) or less who do not have an on-site distributed generation system. For new customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site. Annual reassignment will begin with January 2019 bills.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy (kWh) is used during the month. This rate does not have time-of-use charges, seasonal charges, or a demand charge.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	\$0.329	per day
Energy Charge	\$0.11672	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	\$0.072	per day
Metering Charge	\$0.104	per day
Meter Reading Charge	\$0.072	per day
Billing Charge	\$0.081	per day

Energy Charge Components

System Benefits Charge:	\$0.00276	per kWh
Transmission Charge	\$0.01097	per kWh
Delivery Charge	\$0.03112	per kWh
Generation Charge	\$0.07187	per kWh



RATE SCHEDULE R-XS EXTRA SMALL RESIDENTIAL SERVICE

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedules EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
8. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 1/2 HP or more.



**RATE SCHEDULE R-XS
EXTRA SMALL RESIDENTIAL SERVICE**

3. Electric service is supplied at a single point of delivery and measured through a single meter.
4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown below.



RATE SCHEDULE R-BASIC SMALL RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to residential Customers with an annual average monthly energy usage of more than 600 but less than 1,000 kilowatt-hours (kWh) who do not have an on-site distributed generation system. For new customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site. Annual reassignment will begin with January 2019 bills.

Starting May 1, 2018, first-time Customers are not eligible for this rate for a period of ninety (90) days from the date service begins. After this initial 90-day period, qualifying Customers may move to this rate at any time but must remain on this R-Basic rate schedule for at least twelve (12) consecutive months before moving to another residential rate schedule for which the Customer may qualify.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy (kWh) is used during the month. This rate does not vary by time-of-use, season, or demand (how much energy is used at one time).

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	\$0.493	per day
Energy Charge	\$0.12393	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	\$0.125	per day
Metering Charge	\$0.215	per day
Meter Reading Charge	\$0.072	per day
Billing Charge	\$0.081	per day



**RATE SCHEDULE R-BASIC
SMALL RESIDENTIAL SERVICE**

Energy Charge Components

System Benefits Charge	\$0.00276	per kWh
Transmission Charge	\$0.01097	per kWh
Delivery Charge	\$0.03112	per kWh
Generation Charge	\$0.07908	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power



RATE SCHEDULE R-BASIC SMALL RESIDENTIAL SERVICE

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
3. Electric service is supplied at a single point of delivery and measured through a single meter.
4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.



RATE SCHEDULE R-BASIC L LARGE RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to residential Customers with an annual average monthly energy usage of 1,000 kilowatt-hours (kWh) or more who do not have an on-site distributed generation system. For new customers, initial annual average monthly energy usage will be based on historical energy consumption at the Customer's site.

Eligibility for this rate schedule will be frozen on May 1, 2018. After this date, Customers may not elect to take service under this rate, whether they are new or moving from a different rate. Charges on this schedule may change.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. Energy charges are based on how much energy (kWh) is used during the month. This rate does not vary by time-of-use, season, or demand (how much energy is used at one time).

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	\$0.658	per day
Energy Charge	\$0.13412	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	\$0.290	per day
Metering Charge	\$0.215	per day
Meter Reading Charge	\$0.072	per day
Billing Charge	\$0.081	per day



RATE SCHEDULE R-BASIC L LARGE RESIDENTIAL SERVICE

Energy Charge Components

System Benefits Charge	\$0.00276	per kWh
Transmission Charge	\$0.01097	per kWh
Delivery Charge	\$0.03112	per kWh
Generation Charge	\$0.08927	per kWh

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power



RATE SCHEDULE R-BASIC L LARGE RESIDENTIAL SERVICE

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
3. Electric service is supplied at a single point of delivery and measured through a single meter.
4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.



RATE SCHEDULE TOU-E RESIDENTIAL TIME-OF-USE SERVICE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

DESCRIPTION

This rate has two parts: a basic service charge and an energy charge. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). This rate does not include a demand charge.

TIME PERIODS

The On-Peak time period for residential rate schedules is 3 p.m. to 8 p.m. Monday through Friday year round. This rate also has a Super Off-Peak period, which is 10 a.m. to 3 p.m. Monday through Friday during the winter billing cycles of November through April. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge	\$0.427	per day
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**RATE SCHEDULE TOU-E
RESIDENTIAL TIME-OF-USE SERVICE**

Bundled Charges continued:

	Summer	Winter	
On-Peak Energy Charge	\$0.24314	\$0.23068	per kWh
Off-Peak Energy Charge	\$0.10873	\$0.10873	per kWh
Super Off-Peak Energy Charge		\$0.03200	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	\$0.073	per day
Metering Charge	\$0.201	per day
Meter Reading Charge	\$0.072	per day
Billing Charge	\$0.081	per day

Energy Charge Components

System Benefits Charge	\$0.00276	per kWh
Transmission Charge	\$0.01097	per kWh

	Summer	Winter	
Delivery Charge	\$0.03112	\$0.01105	per kWh
Generation On-Peak Charge	\$0.19829	\$0.18583	per kWh
Generation Off-Peak Charge	\$0.06388	\$0.06388	per kWh
Generation Super Off-Peak Charge		\$0.00722	per kWh

CHARGE FOR ON-SITE DISTRIBUTED GENERATION CUSTOMERS

The monthly bill for Customers on this rate schedule who have an on-site distributed generation system will also include a Grid Access Charge. This charge will apply to the nameplate kW-dc power rating of the Customer's distributed generation facility:

Grid Access Charge	\$0.93	per kW-dc of generation
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RATE SCHEDULE TOU-E RESIDENTIAL TIME-OF-USE SERVICE

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP (RES)	Critical Peak Pricing (Residential)
EPR-2	Partial Requirements
EPR-6	Partial Requirements - Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power



RATE SCHEDULE TOU-E RESIDENTIAL TIME-OF-USE SERVICE

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
3. Electric service is supplied at a single point of delivery and measured through a single meter.
4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.



RATE SCHEDULE R-2 RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will not vary by season.

TIME PERIODS

The On-Peak time period for residential rate schedules is 3 p.m. to 8 p.m. Monday through Friday year round. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:



**RATE SCHEDULE R-2
RESIDENTIAL SERVICE**

Bundled Charges

Basic Service Charge:	\$0.427	per day
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	Summer	Winter	
On-Peak Demand Charge:	\$8.40	\$8.40	per kW
On-Peak Energy Charge:	\$0.13160	\$0.11017	per kWh
Off-Peak Energy Charge:	\$0.07798	\$0.07798	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	\$0.073	per day
Metering Charge	\$0.201	per day
Meter Reading Charge	\$0.072	per day
Billing Charge	\$0.081	per day

Demand Charge Components

Delivery On-Peak kW Charge	\$4.000	per kW
Generation On-Peak kW Charge	\$4.400	per kW

Energy Charge Components

System Benefits Charge:	\$0.00276	per kWh
Transmission Charge:	\$0.01097	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	\$0.01105	\$0.01105	per kWh
Generation On-Peak kWh Charge:	\$0.10682	\$0.08539	per kWh
Generation Off-Peak kWh Charge:	\$0.05320	\$0.05320	per kWh



RATE SCHEDULE R-2 RESIDENTIAL SERVICE

The kW used to determine the demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour On-Peak period for the billing month.

For full requirements Customers, billing demands are limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month. This limitation is not available to partial requirements Customers.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CPP-RES	Critical Peak Pricing (Residential)
E-3	Limited income discount
E-4	Limited income medical discount
EPR-2	Partial Requirements
EPR-6	Partial Requirements - Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
GPS-1, GPS-2, GPS-3	Green Power



RATE SCHEDULE R-2 RESIDENTIAL SERVICE

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
3. Electric service is supplied at a single point of delivery and measured through a single meter.
4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.
5. Load factor is a relationship between how much energy (kWh) a Customer uses over a period of time and how much demand (kW) is used at one time during that same period, expressed in percentage. The Company will calculate the Customer's load factor for purposes of the billing demand limitation described earlier using the following formula:

$$\text{Monthly Load Factor} = \text{Billed kWh} / (\text{Billed kW} * \text{Billing Days} * 24 \text{ hours})$$



RATE SCHEDULE R-3 RESIDENTIAL SERVICE

AVAILABILITY

This rate schedule is available to all residential Customers, including Partial Requirements Customers with an on-site distributed generation system.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a one hour On-Peak period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter) and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge also varies by season.

TIME PERIODS

The On-Peak time period for residential rate schedules is 3 p.m. to 8 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:



**RATE SCHEDULE R-3
RESIDENTIAL SERVICE**

Bundled Charges

Basic Service Charge:	\$0.427	per day
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	Summer	Winter	
On-Peak Demand Charge:	\$17.438	\$12.239	per kW
On-Peak Energy Charge:	\$0.08683	\$0.06376	per kWh
Off-Peak Energy Charge:	\$0.05230	\$0.05230	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge:	\$0.073	per day
Metering Charge	\$0.201	per day
Meter Reading Charge	\$0.072	per day
Billing Charge	\$0.081	per day

Demand Charge Components

	Summer	Winter	
Delivery On-Peak kW Charge	\$4.000	\$4.000	per kW
Generation On-Peak kW Charge	\$13.438	\$8.239	per kW

Energy Charge Components

System Benefits Charge:	\$0.00276	per kWh
Transmission Charge:	\$0.01097	per kWh

	Summer	Winter	
Delivery Charge for all kWh:	\$0.01105	\$0.01105	per kWh
Generation On-Peak kWh Charge:	\$0.06205	\$0.03898	per kWh
Generation Off-Peak kWh Charge:	\$0.02752	\$0.02752	per kWh



RATE SCHEDULE R-3 RESIDENTIAL SERVICE

The kW used to determine the demand charge above will be the Customer's highest amount of demand (kW) averaged in a one-hour On-Peak period for the billing month..

For full requirements Customers, billing demands are limited to a kW no higher than that which would result in a 15% load factor, based on the Customer's kWh usage during the month. This limitation is not available to partial requirements Customers.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Charge TEAM.
8. Direct Access customers returning to Standard Offer service may be subject to Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
9. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

CCP- RES	Critical Peak Pricing (Residential)
EPR-2	Partial requirements
EPR-6	Partial Requirements - Net Metering (Residential Non-Solar)
RCP	Resource Comparison Proxy
E-3	Limited income discount
E-4	Limited income medical discount



RATE SCHEDULE R-3 RESIDENTIAL SERVICE

GPS-1, GPS-2, GPS-3	Green Power
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SERVICE DETAILS

1. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.
2. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
3. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
4. Electric service is supplied at a single point of delivery and measured through a single meter.
5. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.
6. Load factor is a relationship between how much energy (kWh) a Customer uses over a period of time and how much demand (kW) is used at one time during that same period, expressed in percentage. The Company will calculate the Customer's load factor for purposes of the billing demand limitation described earlier using the following formula:

$$\text{Monthly Load Factor} = \text{Billed kWh} / (\text{Billed kW} * \text{Billing Days} * 24 \text{ hours})$$



**RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE**

AVAILABILITY

This rate schedule is available to residential Customers with the following:

1. Two or more qualifying primary on-site technologies were purchased within 90 days of the customer enrolling in the rate; or
2. One qualifying primary on-site technology was purchased within 90 days of the customer enrolling in the rate and two or more qualifying secondary on-site technologies.

This is a pilot rate schedule. This means this rate is associated with a specific program approved by the Arizona Corporation Commission, and is available only to those customers eligible to participate in the program. The R-Tech pilot program will test the ability and desire of participating residential customers to reduce On-Peak energy and demand usage through multiple behind-the-meter technologies.

Qualifying technologies for the R-Tech pilot program are as follows:

1. Primary technologies:
 - a. A rooftop solar photovoltaic system. The size of the system cannot be smaller than 2 kW-dc. For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).
 - b. A chemical storage system. The size of the system cannot be smaller than 4 kWh. There is no maximum limitation for this technology.
 - c. An electric vehicle. There are no limitations for this technology.
2. Secondary technologies:
 - a. A device with a variable speed motor (such as a variable speed pool pump or a variable speed Heating, Ventilating, and Air Conditioning (HVAC) system).
 - b. A grid-interactive water heating system.
 - c. A smart thermostat.
 - d. An automated load controller.

This rate schedule is initially limited to a maximum of 10,000 residential customers as outlined in Decision No. xxxxx.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the amount of demand (kW) averaged in a one hour period for the month, and an energy charge for the total energy (kWh) used for the entire month. The energy charge will vary by season (summer or winter)



RATE SCHEDULE R-TECH RESIDENTIAL SERVICE PILOT TECHNOLOGY RATE

and by the time of day that the energy is used (On-Peak or Off-Peak). The demand charge will also vary by season (summer or winter) and time of day (On-Peak or Off-Peak).

TIME PERIODS

The On-Peak time period for residential rate schedules is 3 p.m. to 8 p.m. Monday through Friday. All other hours are Off-Peak hours.

The following holidays are also included in the Off-Peak hours:

- New Year's Day - January 1*
- Martin Luther King Day - Third Monday in January
- Presidents Day - Third Monday in February
- Cesar Chavez Day - March 31*
- Memorial Day - Last Monday in May
- Independence Day - July 4*
- Labor Day - First Monday in September
- Veterans Day - November 11*
- Thanksgiving - Fourth Thursday in November
- Christmas Day - December 25*

*If these holidays fall on a Saturday, the preceding Friday will be Off-peak. If they fall on a Sunday, the following Monday will be Off-Peak.

The rate also varies by summer and winter seasons. The summer season is the May through October billing cycles and the winter season is the November through April billing cycles.

CHARGES

This monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge		\$0.493	per day	
		Summer	Winter	
On-Peak Demand Charge		\$20.25	\$14.25	per kW
Off-Peak Demand Charge	First 5 kW	\$0.00	\$0.00	per kW
	All remaining kW	\$6.50	\$6.50	



**RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE**

On-Peak Energy Charge	\$0.05750	\$0.04750	per kWh
Off-Peak Energy Charge	\$0.04750	\$0.04750	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	\$0.125	per day
Metering Charge	\$0.215	per day
Meter Reading Charge	\$0.072	per day
Billing Charge	\$0.081	per day

Demand Charge Components

	Summer	Winter	
On-Peak Generation Charge	\$13.750	\$7.750	per kW
Off-Peak Generation Charge	First 5 kW	\$0.000	per kW
	All remaining kW	\$1.000	per kW
On-Peak Delivery Charge	\$6.500	\$6.500	per kW
Off-Peak Delivery Charge	First 5 kW	\$0.000	per kW
	All remaining kW	\$5.500	

Energy Charge Components

System Benefits Charge	\$0.00276	per kWh
Transmission Charge	\$0.01097	per kWh
Delivery Charge for all kWh	\$0.00210	per kWh

	Summer	Winter	
Generation On-Peak kWh Charge	\$0.04167	\$0.03167	per kWh
Generation Off-Peak kWh Charge	\$0.03167	\$0.03167	per kWh

The kW used to determine the On-Peak demand charge above will be the Customer's highest amount of demand (kW) averaged in a one hour On-Peak period for the month.



**RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE**

The kW used to determine the Off-Peak demand charge above will be the Customer's highest amount of demand (kW) averaged in a one hour Off-Peak period during the weekday (Monday through Friday), excluding holidays that may fall on a weekday.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charge, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Lost Fixed Cost Recovery Adjustment charge, Adjustment Schedule LFCR.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

RCP	Resource Comparison Proxy
EPR-2	Partial Requirements
EPR-6	Partial Requirements - Net Metering (Residential Non-Solar)
E-3	Limited income discount
E-4	Limited income medical discount
GPS-1, GPS-2, GPS-3	Green Power

SERVICE DETAILS

1. This pilot rate schedule requires the Customer to have a standard AMI meter in place.



**RATE SCHEDULE R-TECH
RESIDENTIAL SERVICE
PILOT TECHNOLOGY RATE**

2. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the Partial Requirements Service rate riders.
3. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
4. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
5. Electric service is supplied at a single point of delivery and measured through a single meter.
6. Direct Access customers are not eligible for this rate schedule.

Appendix G

Settlement Rate Summary for Residential Rates

	TOU-E	R-2	R-3		R-TECH
Bundled Rates				Bundled Rates	
Summer				Summer	
BSC \$/day	0.427	0.427	0.427	BSC \$/day	0.493
On kW		8.400	17.438	On kW	20.250
On-peak kWh	0.24314	0.13160	0.08683	Off kW	6.500
Off-peak kWh	0.10873	0.07798	0.05230	On-peak kWh	0.05750
Winter				Off-peak kWh	0.04750
BSC \$/day	0.427	0.427	0.427	Winter	
On kW		8.400	12.239	BSC \$/day	0.493
On-peak kWh	0.23068	0.11017	0.06376	On kW	14.250
Off-peak kWh	0.10873	0.07798	0.05230	Off kW	6.500
Super Off-peak kWh	0.03200			On-peak kWh	0.04750
				Off-peak kWh	0.04750
				Super Off-peak kWh	
Unbundled Rates				Unbundled Rates	
Generation - Summer				Generation - Summer	
kWh - on	0.19829	0.10682	0.06205	kWh - on	0.04167
kWh - off	0.06388	0.05320	0.02752	kWh - off	0.03167
kW - on		4.400	13.438	kW - on	13.750
Generation - Winter				kW - off	1.000
kWh - on	0.18583	0.08539	0.03898	Generation - Winter	
kWh - off	0.06388	0.05320	0.02752	kWh - on	0.03167
kWh - super off	0.00722			kWh - off	0.03167
kW - on		4.400	8.239	kW - on	7.750
Transmission - kWh	0.01097	0.01097	0.01097	kW - off	1.000
Delivery - Summer				Transmission - kWh	0.01097
kWh	0.03112	0.01105	0.01105	Delivery	
kW		4.000	4.000	kWh	0.00210
Delivery - Winter				kW - on	6.500
kWh	0.01105	0.01105	0.01105	kW - off	5.500
kW		4.000	4.000	System Benefits - kWh	0.00276
System Benefits - kWh	0.00276	0.00276	0.00276	BCS \$-Day	
BSC \$/day				Customer accounts	0.125
Customer accounts	0.073	0.073	0.073	Metering	0.215
Metering	0.201	0.201	0.201	Billing	0.081
Billing	0.081	0.081	0.081	Meter reading	0.072
Meter reading	0.072	0.072	0.072		

Settlement Rate Summary for Residential Rates

	R-XS	R-BASIC	R-BASIC L	Transition E-12 Bundled Rates	
Bundled Rates				Summer	
Summer & Winter				BSC \$/day	0.330
BSC \$/day	0.329	0.493	0.658	0-400 kWh	0.11161
kWh	0.11672	0.12393	0.13412	401-800 kWh	0.15920
				801-3000 kWh	0.18627
Unbundled Rates				< 3000 kWh	0.19863
Generation kWh	0.07187	0.07908	0.08927	Winter	
Transmission - kWh	0.01097	0.01097	0.01097	BSC \$/day	0.330
Delivery kWh	0.03112	0.03112	0.03112	All kWh	0.10851
System Benefits - kWh	0.00276	0.00276	0.00276		
BSC \$/day				Unbundled Rates	
Customer accounts	0.072	0.125	0.290	Generation - Summer	
Metering	0.104	0.215	0.215	1st 400 kWh	0.06676
Billing	0.081	0.081	0.081	Next 400 kWh	0.11435
Meter reading	0.072	0.072	0.072	Next 2200 kWh	0.14142
				All other kWh	0.15378
				Generation Winter - kWh	0.06366
				Transmission - kWh	0.01097
				Delivery kWh	0.03112
				System Benefits - kWh	0.00276
				BSC \$/day	
				Customer accounts	0.073
				Metering	0.104
				Billing	0.081
				Meter reading	0.072

Settlement Rate Summary for Residential Rates

Transition TOU-E Bundled Rates		Transition TOU-D Bundled Rates		Transition TOU-D Bundled Rates	
	ET-1	ET-2		ECT-1R	ECT-2
Summer			Summer		
BSC \$/day	0.643	0.643	BSC \$/day	0.643	0.643
On-Peak kWh	0.20697	0.28205	kW	15.69	15.61
Off-Peak kWh	0.06697	0.07105	On-Peak kWh	0.08490	0.10256
Winter			Off-Peak kWh	0.04730	0.05109
BSC \$/day	0.643	0.643	Winter		
On-Peak kWh	0.16794	0.22900	BSC \$/day	0.643	0.643
Off-Peak kWh	0.06397	0.07005	kW	10.89	10.76
			On-Peak kWh	0.06470	0.06647
			Off-Peak kWh	0.04594	0.04750
Unbundled Rates			Unbundled Rates		
Generation - Summer			Generation - Summer		
On-Peak kWh	0.16211	0.23715	On-Peak kWh	0.05332	0.07264
Off-Peak kWh	0.02211	0.02615	Off-Peak kWh	0.01572	0.02117
Generation - Winter			kW	11.17500	10.40900
On-Peak kWh	0.12308	0.18410	Generation - Winter		
Off-Peak kWh	0.01911	0.02515	On-Peak kWh	0.03128	0.03435
Transmission - kWh	0.01097	0.01097	Off-Peak kWh	0.01252	0.01538
Delivery kWh	0.03113	0.03117	kW	8.22200	7.98000
System Benefits - kWh	0.00276	0.00276	Transmission - kWh	0.01097	0.01097
BSC \$/day			Delivery		
Customer accounts	0.27500	0.27500	Summer kWh	0.01785	0.01619
Metering	0.21500	0.21500	Summer kW	4.51600	5.20500
Billing	0.08100	0.08100	Winter kWh	0.01969	0.01839
Meter reading	0.07200	0.07200	Winter kW	2.66300	2.77600
			System Benefits - kWh	0.00276	0.00276
			BSC \$/day		
			Customer accounts	0.27500	0.27500
			Metering	0.21500	0.21500
			Billing	0.08100	0.08100
			Meter reading	0.07200	0.07200
			Total Non-timed kWh		
			Summer kWh	0.03156	0.02992
			Winter kWh	0.03342	0.03212

Settlement Rate Summary for Residential Rates

Solar Legacy E-12 Bundled Rates		Solar Legacy TOU-E Bundled Rates		ET-1	ET-2
Summer		Summer			
BSC \$/day	0.330	BSC \$/day		0.643	0.643
0-400 kWh	0.11161	On-Peak kWh		0.20697	0.28205
401-800 kWh	0.15920	Off-Peak kWh		0.06697	0.07105
801-3000 kWh	0.18627	Winter			
< 3000 kWh	0.19863	BSC \$/day		0.643	0.643
Winter		On-Peak kWh		0.16794	0.22900
BSC \$/day	0.330	Off-Peak kWh		0.06397	0.07005
All kWh	0.10851				
Unbundled Rates		Unbundled Rates			
Generation - Summer		Generation - Summer			
1st 400 kWh	0.06676	On-Peak kWh		0.16211	0.23715
Next 400 kWh	0.11435	Off-Peak kWh		0.02211	0.02615
Next 2200 kWh	0.14142	Generation - Winter			
All other kWh	0.15378	On-Peak kWh		0.12308	0.18410
Generation Winter - kWh	0.06366	Off-Peak kWh		0.01911	0.02515
Transmission - kWh	0.01097	Transmission - kWh		0.01097	0.01097
Delivery kWh	0.03112	Delivery kWh		0.03113	0.03117
System Benefits - kWh	0.00276	System Benefits - kWh		0.00276	0.00276
BSC \$/day		BSC \$/day			
Customer accounts	0.07300	Customer accounts		0.27500	0.27500
Metering	0.10400	Metering		0.21500	0.21500
Billing	0.08100	Billing		0.08100	0.08100
Meter reading	0.07200	Meter reading		0.07200	0.07200
		Total untimed kWh		0.04486	0.04490

Settlement Rate Summary for Residential Rates

Solar Legacy TOU-D Bundled Rates			
	ECT-1R	ECT-2	
Summer			
BSC \$/day	0.643	0.643	
kW	15.69	15.61	
On-Peak kWh	0.08490	0.10256	
Off-Peak kWh	0.04730	0.05109	
Winter			
BSC \$/day	0.643	0.643	
kW	10.89	10.76	
On-Peak kWh	0.06470	0.06647	
Off-Peak kWh	0.04594	0.04750	
Unbundled Rates			
Generation - Summer			
On-Peak kWh	0.05332	0.07264	
Off-Peak kWh	0.01572	0.02117	
kW	11.17500	10.40900	
Generation - Winter			
On-Peak kWh	0.03128	0.03435	
Off-Peak kWh	0.01252	0.01538	
kW	8.22200	7.98000	
Transmission - kWh			
	0.01097	0.01097	
Delivery			
Summer kWh	0.01785	0.01619	
Summer kW	4.51600	5.20500	
Winter kWh	0.01969	0.01839	
Winter kW	2.66300	2.77600	
System Benefits - kWh			
	0.00276	0.00276	
BSC \$/day			
Customer accounts	0.27500	0.27500	
Metering	0.21500	0.21500	
Billing	0.08100	0.08100	
Meter reading	0.07200	0.07200	
Total Non-timed kWh			
Summer kWh	0.03156	0.02992	
Winter kWh	0.03342	0.03212	

Settlement Rate Summary for General Service Rates

E-20 House of Worship Bundled Rates		E-30 Non-Metered Bundled Rates		E-32 XS D Bundled Rates	
Summer		Summer		Summer	
BSC \$/day	2.020	BSC \$/day	0.405	BSC \$/day	
kW on-peak	3.800	kWh	0.13791	Self contained meter	1.160
kW excess	2.400	Winter		Instrument rated meter	2.020
On-peak kWh	0.15458	BSC \$/day	0.405	Primary meter	4.947
Off-peak kWh	0.07519	kWh	0.12443		
Winter		Unbundled Rates		Summer	
BSC \$/day	2.020	Generation - Summer		kW Secondary	6.900
kW on-peak	3.800	kWh	0.07972	kW Primary	4.300
kW excess	2.400	Generation - Winter		kWh secondary	0.10549
On-peak kWh	0.13626	kWh	0.06624	kWh- primary	0.09951
Off-peak kWh	0.06748	Transmission	0.00794	Winter	
Minimum		Delivery	0.04749	kW Secondary	6.90
BSC(Days)	2.020	Systems Benefits	0.00276	kW Primary	4.30
KW	3.101	BSC \$/day		kWh secondary	0.08631
Unbundled Rates		Customer accounts	0.375	kWh- primary	0.08051
Generation		Billing	0.030	Unbundled Rates	
kWh summer - on	0.11390			Generation	
kWh summer - off	0.03451			Summer kWh	0.08081
kWh winter - on	0.09558			Winter kWh	0.06181
kWh winter - off	0.02680			Delivery - Summer	
Delivery kW - on	0.930			kWh secondary	0.01398
Delivery kW - excess	2.400			kWh- primary	0.00800
Delivery kWh	0.03792			kW secondary	6.900
Transmission - kW - on	2.870			kW primary	4.300
Systems Benefits - kWh	0.00276			Delivery - Winter	
BSC \$/day				kWh secondary	0.01380
Customer accounts	0.504			kWh- primary	0.00800
Billing	0.030			kW secondary	6.900
Meter reading	0.009			kW primary	4.300
Metering - self contained				Transmission - kWh	0.00794
Metering - instrument rated	1.477			Systems Benefits - kWh	0.00276
Metering - primary				BSC \$/day	
Metering - Transmission				Customer accounts	0.504
				Billing	0.030
				Meter reading	0.009
				Metering - self contained	0.617
				Metering - instrument rated	1.477
				Metering - primary	4.404
				Billing	0.030
				Meter reading	0.009
				Metering - self contained	0.617
				Metering - instrument rated	1.477
				Metering - primary	4.404
				kWh Schools discount	-0.0024

Settlement Rate Summary for General Service Rates

E-32 XS Bundled Rates		Solar billing determinants E-32 XS Bundled Rates		E-32 S Bundled Rates	
BSC \$/day		BSC \$/day		BSC \$/day	
Self contained meter	1.160	Self contained meter	1.160	Self contained meter	1.160
Instrument rated meter	2.020	Instrument rated meter	2.020	Instrument rated meter	2.020
Primary meter	4.947	Primary meter	4.947	Primary meter	4.947
Summer		Summer		Demand	
kWh secondary tier 1	0.13514	kWh secondary tier 1	0.13514	kW tier 1 - secondary	11.360
kWh secondary tier 2	0.07612	kWh secondary tier 2	0.10762	kW tier 2 - secondary	6.608
kWh primary tier 1	0.13195	kWh primary tier 1	0.13195	kW tier 1 - primary	10.627
kWh primary tier 2	0.07264	kWh primary tier 2	0.10414	kW tier 2 - primary	5.875
Winter		Winter		Summer	
kWh secondary tier 1	0.11797	kWh secondary tier 1	0.11797	kWh secondary tier 1	0.10828
kWh secondary tier 2	0.05864	kWh secondary tier 2	0.09015	kWh secondary tier 2	0.06535
kWh primary tier 1	0.11476	kWh primary tier 1	0.11476	Winter	
kWh primary tier 2	0.05545	kWh primary tier 2	0.08696	kWh secondary tier 1	0.09126
				kWh secondary tier 2	0.04836
Unbundled Rates		Unbundled Rates		Unbundled Rates	
Generation - Summer		Generation - Summer		Generation - Summer	
kWh tier 1	0.08390	kWh tier 1	0.08390	kWh tier 1	0.09658
kWh tier 2	0.05240	kWh tier 2	0.08390	kWh tier 2	0.05365
Generation - Winter		Generation - Winter		Generation - Winter	
kWh tier 1	0.06680	kWh tier 1	0.06680	kWh tier 1	0.07956
kWh tier 2	0.03529	kWh tier 2	0.06680	kWh tier 2	0.03666
Delivery - Summer		Delivery - Summer		Delivery	
kWh tier 1 - secondary	0.04054	kWh tier 1 - secondary	0.04054	kW tier 1 - secondary	8.490
kWh tier 2 - secondary	0.01302	kWh tier 2 - secondary	0.01302	kW tier 2 - secondary	3.738
kWh tier 1 - primary	0.03735	kWh tier 1 - primary	0.03735	kW tier 1 - primary	7.757
kWh tier 2 - primary	0.00954	kWh tier 2 - primary	0.00954	kW tier 2 - primary	3.005
Delivery - Winter				kWh	0.00894
kWh tier 1 - secondary	0.04047			Transmission - kW	2.870
kWh tier 2 - secondary	0.01265	Delivery - Winter		Systems Benefits - kWh	0.00276
kWh tier 1 - primary	0.03726	kWh tier 1 - secondary	0.04047	BSC \$/day	
kWh tier 2 - primary	0.00946	kWh tier 2 - secondary	0.01265	Customer accounts	0.504
Transmission - kWh	0.00794	kWh tier 1 - primary	0.03726	Billing	0.030
Systems Benefits - kWh	0.00276	kWh tier 2 - primary	0.00946	Meter reading	0.009
BSC \$/day				Metering - self contained	0.617
Customer accounts	0.504	Transmission - kWh	0.00794	Metering - instrument rated	1.477
Billing	0.030	Systems Benefits - kWh	0.00276	Metering - primary	4.404
Meter reading	0.009	BSC \$/day		kWh Schools discount	-0.0024
Metering - self contained	0.617	Customer accounts	0.504		
Metering - instrument rated	1.477	Billing	0.030		
Metering - primary	4.404	Meter reading	0.009		
		Metering - self contained	0.617		
		Metering - instrument rated	1.477		
		Metering - primary	4.404		

Settlement Rate Summary for General Service Rates

E-32 M Bundled Rates		E-32 L Bundled Rates		E-34 Bundled Rates	
BSC \$/day		BSC \$/day		BSC \$/day	
Self contained meter	1.160	Self contained meter	3.060	Self contained meter	4.262
Instrument rated meter	2.020	Instrument rated meter	3.920	Instrument rated meter	5.122
Primary meter	4.947	Primary meter	6.847	Primary meter	8.049
Transmission meter	36.795	Transmission meter	38.695	Transmission meter	39.897
Demand		Demand		Demand	
kW tier 1 - secondary	12.124	kW tier 1 - secondary	25.372	Secondary	22.009
kW tier 2 - secondary	6.935	kW tier 2 - secondary	17.605	Primary	20.675
kW tier 1 - primary	11.226	kW tier 1 - primary	23.049	Transmission	14.088
kW tier 2 - primary	6.197	kW tier 2 - primary	16.411	Military	15.051
kW tier 1 - transmission	9.056	kW tier 1 - transmission	17.624	kWh	0.03972
kW tier 2 - transmission	3.869	kW tier 2 - transmission	11.753		
Summer		Summer		Unbundled Rates	
kWh secondary tier 1	0.10532	kWh	0.05540	Generation	
kWh secondary tier 2	0.06475	Winter		kWh	0.03696
Winter		kWh	0.03712	kW	10.464
kWh secondary tier 1	0.08921			Delivery - kW	
kWh secondary tier 2	0.04863			Secondary	8.309
		Unbundled Rates		Primary	6.975
Unbundled Rates		Generation - Summer		Transmission	0.388
Generation - Summer		kWh	0.05264	Military	1.351
kWh tier 1	0.09101	Generation - Winter		Transmission - kW	3.236
kWh tier 2	0.05044	kWh	0.03436	Systems Benefits - kWh	0.00276
Generation - Winter		Generation - kW	5.49600	BSC \$/day	
kWh tier 1	0.07490	Delivery	1.36	Customer accounts	3.606
kWh tier 2	0.03432	kW tier 1 - secondary	17.00600	Billing	0.030
Delivery		kW tier 2 - secondary	9.23900	Meter reading	0.009
kW tier 1 - secondary	9.25400	kW tier 1 - primary	14.68300	Metering - self contained	0.617
kW tier 2 - secondary	4.06500	kW tier 2 - primary	8.04500	Metering - instrument rated	1.477
kW tier 1 - primary	8.35600	kW tier 1 - transmission	9.25800	Metering - primary	4.404
kW tier 2 - primary	3.32700	kW tier 2 - transmission	3.38700	Metering - Transmission	36.252
kW tier 1 - transmission	6.18600	kWh	-		
kW tier 2 - transmission	0.99900	Transmission - kW	2.870		
kWh	0.01155	Systems Benefits - kWh	0.00276		
Transmission - kW	2.870	BSC \$/day			
Systems Benefits - kWh	0.00276	Customer accounts	2.404		
BSC \$/day		Billing	0.030		
Customer accounts	0.504	Meter reading	0.009		
Billing	0.030	Metering - self contained	0.617		
Meter reading	0.009	Metering - instrument rated	1.477		
Metering - self contained	0.617	Metering - primary	4.404		
Metering - instrument rated	1.477	Metering - Transmission	36.252		
Metering - primary	4.404				
Metering - Transmission	36.252	kWh aggregation discount	-0.0024		
		kWh Schools discount	-0.0024		
kWh Schools discount	-0.0024				

Settlement Rate Summary for General Service Rates

E-35 Bundled Rates		E-221 Bundled Rates		E-221 8 T Bundled Rates	
BSC \$/day		BSC \$/day		BSC \$/day	
Self contained meter	4.262	Self contained meter	1.160	Self contained meter	1.160
Instrument rated meter	5.122	Instrument rated meter	2.020	Instrument rated meter	2.020
Primary meter	8.049	Primary meter	4.947	Primary meter	4.947
Transmission meter	39.897				
Demand		Demand		Demand	
Secondary on peak	19.229	kW secondary	4.754	kW secondary on-peak	6.617
off peak	2.975	kWh		kW secondary off-peak	4.410
Primary on peak	17.947	Tier 1	0.10640	kWh	
off peak	2.847	Tier 2	0.07336	on-peak	0.08967
Transmission on peak	11.323			off-peak	0.04808
off peak	2.183				
Military on peak	13.103	Unbundled Rates		Unbundled Rates	
off peak	2.361	Generation		Generation	
kWh on peak	0.04483	kWh - Tier 1	0.07675	kWh - on-peak	0.08517
kWh off peak	0.03550	kWh - Tier 2	0.06115	kWh - off-peak	0.04358
				kW - on-peak	2.20714
		kW	0.99600	kW - off-peak	-
Unbundled Rates		Delivery		Delivery	
Generation		kW Secondary	0.88800	kW Secondary On and Off peak	1.54000
kWh on peak	0.04207	kWh Secondary Tier 1	0.02689	kWh	0.00174
kWh off peak	0.03274	kWh Secondary Tier 2	0.00945	Transmission - kW	2.870
kW on peak	7.49800			Systems Benefits - kWh	0.00276
kW off peak	2.12600	Transmission - kW	2.870	BSC \$/day	
Delivery - kW		Systems Benefits - kWh	0.00276	Customer accounts	0.504
Secondary on peak	8.49500	BSC \$/day		Billing	0.030
off peak	0.84900	Customer accounts	0.504	Meter reading	0.009
Primary on peak	7.21300	Billing	0.030	Metering - self contained	0.617
off peak	0.72100	Meter reading	0.009	Metering - instrument rated	1.477
Transmission on peak	0.58900	Metering - self contained	0.617	Metering - primary	4.404
off peak	0.05700	Metering - instrument rated	1.477		
Military on peak	2.36900	Metering - primary	4.404		
off peak	0.23500				
Transmission - kW	3.236				
Systems Benefits - kWh	0.00276				
BSC \$/day					
Customer accounts	3.606				
Billing	0.030				
Meter reading	0.009				
Metering - self contained	0.617				
Metering - instrument rated	1.477				
Metering - primary	4.404				
Metering - Transmission	36.252				

Settlement Rate Summary for General Service Rates

E-32 TOU XS Bundled Rates		E-32 TOU S Bundled Rates		E-32 TOU M Bundled Rates	
BSC \$/day		BSC \$/day		BSC \$/day	
Self contained meter	1.160	Self contained meter	1.160	Self contained meter	1.160
Instrument rated meter	2.020	Instrument rated meter	2.020	Instrument rated meter	2.020
Primary meter	4.947	Primary meter	4.947	Primary meter	4.947
Summer		Demand		Demand	
kWh - secondary - on	0.13800	kW tier 1 - secondary - on	19.977	kW tier 1 - secondary - on	18.190
kWh - secondary - off	0.10321	kW tier 2 - secondary - on	10.225	kW tier 2 - secondary - on	11.744
kWh - primary - on	0.13600	kW tier 1 - secondary - off	7.879	kW tier 2 - secondary - off	6.742
kWh - primary - off	0.09700	kW tier 2 - secondary - off	2.715	kW tier 1 - secondary - off	3.327
kW - secondary - on	4.546	kW tier 1 - primary - on	19.004	kW tier 2 - secondary - off	17.546
kW - secondary - off	2.599	kW tier 2 - primary - on	10.081	kW tier 1 - primary - on	11.647
kW - primary - on	3.951	kW tier 1 - primary - off	6.657	kW tier 2 - primary - on	5.934
kW - primary - off	1.565	kW tier 2 - primary - off	2.548	kW tier 1 - primary - off	3.216
Winter		Summer		Summer	
kWh - secondary - on	0.10800	kWh - on	0.07161	kW tier 2 - primary - off	16.394
kWh - secondary - off	0.08021	kWh - off	0.05436	kW tier 1 - transmission - on	11.250
kWh - primary - on	0.10600	Winter		kW tier 2 - transmission - on	5.022
kWh - primary - off	0.07400	kWh - on	0.05601	kW tier 1 - transmission - off	3.066
kW - secondary - on	4.546	kWh - off	0.04121	Summer	
kW - secondary - off	2.599	Unbundled Rates		kWh - on	0.07170
kW - primary - on	3.951	Generation - Summer		kWh - off	0.05952
kW - primary - off	1.565	kWh - on	0.06885	Winter	
Unbundled Rates		kWh - off	0.05160	kWh - on	0.05783
Generation - Summer		Generation - Winter		kWh - off	0.04566
kWh - on	0.08100	kWh - on	0.05325	Unbundled Rates	
kWh - off	0.06700	kWh - off	0.03845	Generation - Summer	
kW - on	2.95100	Generation - kW		kWh - on	0.05756
kW - off	1.51500	kW - on	4.83700	kWh - off	0.04538
Generation - Winter		kW - off	1.84000	Generation - Winter	
kWh - on	0.05100	Delivery		kWh - on	0.04369
kWh - off	0.04400	kW tier 1 - secondary - on	12.27000	kWh - off	0.03152
kW - on	2.951	kW tier 2 - secondary - on	2.51800	Generation - kW	
kW - off	1.515	kW tier 1 - secondary - off	6.03900	kW - on	4.91300
Delivery		kW tier 2 - secondary - off	0.87500	kW - off	1.87000
kWh - secondary - on	0.05700	kW tier 1 - primary - on	11.29700	Delivery	
kWh - secondary - off	0.03621	kW tier 2 - primary - on	2.37400	kW tier 1 - secondary - on	10.40700
kWh - primary - on	0.05500	kW tier 1 - primary - off	4.81700	kW tier 2 - secondary - on	3.96100
kWh - primary - off	0.03000	kW tier 2 - primary - off	0.70800	kW tier 1 - secondary - off	4.87200
kW - secondary - on	1.595	Transmission - kW		kW tier 2 - secondary - off	1.45700
kW - secondary - off	1.084	Systems Benefits - kWh		kW tier 1 - primary - on	9.76300
kW - primary - on	1.000	BSC \$/day		kW tier 2 - primary - on	3.86400
kW - primary - off	0.050	Customer accounts	0.504	kW tier 1 - primary - off	4.06400
Transmission - kWh	0.00794	Billing	0.030	kW tier 2 - primary - off	1.34600
Systems Benefits - kWh	0.00276	Meter reading	0.009	kW tier 1 - transmission - on	8.61100
BSC \$/day		Metering - self contained	0.617	kW tier 2 - transmission - on	3.46700
Customer accounts	0.504	Metering - instrument rated	1.477	kW tier 1 - transmission - off	3.15200
Billing	0.030	Metering - primary	4.404	kW tier 2 - transmission - off	1.19600
Meter reading	0.009	kWh Schools discount		kWh	0.01138
Metering - self contained	0.617	-0.0024		Transmission - kW	
Metering - instrument rated	1.477			Systems Benefits - kWh	
Metering - primary	4.404			BSC \$/day	
kWh Schools discount				Customer accounts	0.504
-0.0024				Billing	0.030
				Meter reading	0.009
				Metering - self contained	0.617
				Metering - instrument rated	1.477
				Metering - primary	4.404
				Metering - transmission	36.252
				kWh Schools discount	
				-0.0024	

Settlement Rate Summary for General Service Rates

E-32 TOU L Bundled Rates		GS-Schools M Bundled Rates		GS-Schools L Bundled Rates	
BSC \$/day		BSC \$/day		BSC \$/day	
Self contained meter	3.060	Self contained meter	1.160	Self contained meter	3.060
Instrument rated meter	3.920	Instrument rated meter	2.020	Instrument rated meter	3.920
Primary meter	6.847	Primary meter	4.947	Primary meter	6.847
Transmission meter	38.695	Transmission meter	36.795	Transmission meter	38.695
Demand		Demand		Demand	
kW tier 1 - secondary - on	17.508	kW tier 1 - secondary	11.816	kW tier 1 - secondary	11.564
kW tier 2 - secondary - on	11.795	kW tier 2 - secondary	6.802	kW tier 2 - secondary	6.661
kW tier 1 - secondary - off	6.396	kW tier 1 - primary	11.044	kW tier 1 - primary	10.804
kW tier 2 - secondary - off	3.370	kW tier 2 - primary	6.028	kW tier 2 - primary	5.905
kW tier 1 - primary - on	16.936	kW tier 1 - transmission	8.853	kW tier 1 - transmission	8.666
kW tier 2 - primary - on	11.710	kW tier 2 - transmission	3.839	kW tier 2 - transmission	3.761
kW tier 1 - primary - off	5.679	Summer - Peak		Summer - Peak	
kW tier 2 - primary - off	3.272	kWh - on	0.18571	kWh - on	0.16704
kW tier 1 - transmission - on	15.916	kWh - shoulder	0.13746	kWh - shoulder	0.12360
kW tier 2 - transmission - on	10.478	kWh - off	0.06920	kWh - off	0.06809
kW tier 1 - transmission - off	4.871	Summer - Shoulder		Summer - Shoulder	
kW tier 2 - transmission - off	3.137	kWh - on	0.16032	kWh - on	0.14419
Summer		kWh - shoulder	0.11865	kWh - shoulder	0.10667
kWh - on	0.07018	kWh - off	0.05952	kWh - off	0.05163
kWh - off	0.05730	Winter		Winter	
Winter		kWh - on	0.12415	kWh - on	0.11163
kWh - on	0.05552	kWh - shoulder	0.09186	kWh - shoulder	0.08257
kWh - off	0.04264	kWh - off	0.04617	kWh - off	0.04541
Unbundled Rates		Unbundled Rates		Unbundled Rates	
Generation - Summer		Generation - Summer Peak		Generation - Summer Peak	
kWh - on	0.05534	kWh - on	0.16003	kWh - on	0.14913
kWh - off	0.04246	kWh - shoulder	0.11178	kWh - shoulder	0.10569
Generation - Winter		kWh - off	0.04352	kWh - off	0.05018
kWh - on	0.04068	Generation - Summer Shoulder		Generation - Summer Shoulder	
kWh - off	0.02780	kWh - on	0.13464	kWh - on	0.12628
Generation - kW		kWh - shoulder	0.09297	kWh - shoulder	0.08876
kW - on	5.98000	kWh - off	0.03384	kWh - off	0.03372
kW - off	2.27500	Generation - Winter		Generation - Winter	
Delivery		kWh - on	0.09847	kWh - on	0.09372
kW tier 1 - secondary - on	8.658	kWh - shoulder	0.06618	kWh - shoulder	0.06466
kW tier 2 - secondary - on	2.945	kWh - off	0.02049	kWh - off	0.02750
kW tier 1 - secondary - off	4.121	Generation - kW		Generation - kW	
kW tier 2 - secondary - off	1.095	kW		kW	
kW tier 1 - primary - on	8.086	Delivery		Delivery	
kW tier 2 - primary - on	2.860	kW tier 1 - secondary	8.946	kW tier 1 - secondary	8.694
kW tier 1 - primary - off	3.404	kW tier 2 - secondary	3.932	kW tier 2 - secondary	3.791
kW tier 2 - primary - off	0.997	kW tier 1 - primary	8.174	kW tier 1 - primary	7.934
kW tier 1 - transmission - on	7.066	kW tier 2 - primary	3.158	kW tier 2 - primary	3.035
kW tier 2 - transmission - on	1.628	kW tier 1 - transmission	5.983	kW tier 1 - transmission	5.796
kW tier 1 - transmission - off	2.596	kW tier 2 - transmission	0.969	kW tier 2 - transmission	0.891
kW tier 2 - transmission - off	0.862	kWh	0.02292	kWh	0.01515
kWh	0.01208	Transmission - kW	2.870	Transmission - kW	2.870
Transmission - kW	2.870	Systems Benefits - kWh	0.00276	Systems Benefits - kWh	0.00276
Systems Benefits - kWh	0.00276	BSC \$/day		BSC \$/day	
BSC \$/day		Customer accounts	0.504	Customer accounts	2.404
Customer accounts	2.404	Billing	0.030	Billing	0.030
Billing	0.030	Meter reading	0.009	Meter reading	0.009
Meter reading	0.009	Metering - self contained	0.617	Metering - self contained	0.617
Metering - self contained	0.617	Metering - instrument rated	1.477	Metering - instrument rated	1.477
Metering - instrument rated	1.477	Metering - primary	4.404	Metering - primary	4.404
Metering - primary	4.404	Metering - transmission	36.252	Metering - transmission	36.252
Metering - transmission	36.252				
kWh aggregation discount	-0.0024	kWh Schools discount	-0.0024	kWh Schools discount	-0.0024
kWh Schools discount	-0.0024				

Settlement Rate Summary for General Service Rates

E-59 Bundled Rates		SL Contract Bundled Rates		E-67 Bundled Rates	
0.0000	3.0000	Delivery Point	17.73	kWh	0.05364
kWh	0.06563	kWh	0.09147		

Settlement Rate Summary for General Service Rates

XHLF Rate Bundled Rates		E-36 XL Bundled Rates		E-36 M (Rider) Bundled Rates	
BSC \$/day		Basic Service Charge		BSC \$/day	
Instrument rated meter	5.122		7,436	E32-XS option	
Primary meter	8.049	T&D Capacity Charge:		Self contained meter	3.764
Transmission meter	39.897	Secondary	5.584	Instrument rated meter	4.602
Demand (kW)		Primary	5.388	Primary meter	13.037
Secondary	17.950	Transmission	1.743		
Primary	16.609	Hourly Proxy		E32-L option	
Transmission	12.917	Power Supply kWh	0.00061	Self contained meter	3.764
kWh	0.037610			Instrument rated meter	4.602
				Primary meter	13.037
				Transmission meter	44.885
Unbundled Rates				Unbundled Rates	
Generation - kWh				BSC (day)	
kW	9.27400			E32-XS option	
kWh	0.03485			Customer accounts:	
Delivery - kW (primary)				Self contained meter	3.14700
Secondary	5.44000			Instrument rated meter	3.12500
Primary	4.09900			Primary meter	8.63300
Transmission	0.40700			Metering:	
Transmission - kW	3.236			Self contained meter	0.61700
Systems Benefits - kv	0.00276			Instrument rated meter	1.47700
BSC (day)				Primary meter	4.40400
Customer accounts	3.606			Meter Reading	0.00900
Billing	0.030			Billing	0.03000
Meter reading	0.009			kWh rate - summer	0.13514
Metering - instrumen	1.477			kWh rate - winter	0.11797
Metering - primary	4.404				
Metering - Transmissi	36.252			E32-L option	
				Customer accounts:	
				Self contained meter	3.14700
				Instrument rated meter	3.12500
				Primary meter	8.63300
				Metering:	
				Self contained meter	0.61700
				Instrument rated meter	1.47700
				Primary meter	4.40400
				Transmission meter	36.25200
				Meter Reading	0.00900
				Billing	0.03000

Settlement Rate Summary for General Service Rates

E 56		Rider PPR	
Back-up Power Charges			
Rate Schedule F 34	0.647	Extra Large	0.75147
Rate Schedule F 32	0.131	Large - summer	0.06080
Excess power charge		Large - winter	0.04450
secondary	0.54802	Medium - summer	0.06623
primary	0.52019	Medium - winter	0.05770
transmission	0.08187		

Appendix H



PLAN OF ADMINISTRATION
RESOURCE COMPARISON PROXY

Resource Comparison Proxy
Plan of Administration

Table of Contents

1. General Description	1
2. Customer Billing	1
3. Resource Comparison Proxy Purchase Rate	1
4. Definitions	2
5. System Eligibility	3
6. Calculation of Resource Comparison Proxy Purchase Rate	4
7. Procedural Timeline	6
8. Confidential Data	6
9. Schedules	6

1. General Description

This document describes the plan for administering the Resource Comparison Proxy purchase rate (RCP) approved for Arizona Public Service Company (APS or Company) in Arizona Corporation Commission (Commission) Decision No. 75859 (January 3, 2017), as modified by Decision No. 75932 (January 13, 2017) and implemented in Decision No. xxxxx (xxx x, 2017). The RCP is the price at which the Company purchases Exported Energy from residential Customers with qualified on-site solar distributed generation facilities. This price is provided in Rate Rider RCP.

The RCP is a proxy for the avoided cost of providing electrical service that results when a distributed generator exports power to the grid. The RCP is calculated using: (i) a rolling historical five-year weighted average cost of grid-scale solar photovoltaic facilities that the Company owns or has rights to through a solar photovoltaic Purchased Power Agreement (PPA); and (ii) applicable Avoided Transmission Capacity Cost, Avoided Distribution Capacity Cost, and Line Losses.

2. Customer Billing

The Company will provide the Customer a monthly bill credit for the Export Energy based on the applicable RCP.

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; if the outstanding credits exceed \$25 a check will automatically be issued; otherwise the bill credits will carry forward to the following year.

3. Resource Comparison Proxy Purchase Rate

The RCP will be determined as follows:



PLAN OF ADMINISTRATION RESOURCE COMPARISON PROXY

- An RCP will be determined for each tranche of new DG Customers, effective July 1 each year without proration. The RCP may not be reduced by more than 10% each year.
- Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before July 1 provided that they subsequently complete the installation and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or APS. In that circumstance, the Customer will have 270 days to complete their interconnection.
- Each Customer's initial RCP will be applicable for 10 years from the time of their interconnection.
- After each Customer's initial 10-year period the bill credit will be based on the purchase rate in effect at that time, and will change from year to year.

4. Definitions

Avoided Cost. In the context of this Plan of Administration, the additional cost APS would incur to acquire electric energy to serve its customers if electricity was not available from on-site distributed generation sources.

Avoided Distribution Capacity Cost. In the context of this Plan of Administration, the net cost of distribution grid equipment and facilities necessary to distribute electricity to APS customers if electricity from on-site distributed generation sources was not available.

Avoided Transmission Capacity Cost. In the context of this Plan of Administration, the additional cost of transmission grid equipment and facilities necessary to transmit electricity to APS customers if electricity from on-site distributed generation sources was not available.

Base Year. For the initial RCP calculation (effective July 1, 2017), the Company's most recent test year, calendar year ending December 31, 2015. Each subsequent annual calculation will use the immediately preceding calendar year as the Base Year. As an example, the RCP that will become effective with the first billing cycle of July 2018 will be calculated with the calendar year ending December 31, 2017 as the Base Year.

Customer(s). For purposes of this Plan of Administration, an APS Customer taking service under a Residential rate schedule.

Export(ed) Energy. Energy generated by an on-site interconnected solar photovoltaic distributed generation source that is greater than the Customer's electric load at any single point in time and flows into the Company's distribution grid.



PLAN OF ADMINISTRATION RESOURCE COMPARISON PROXY

Levelized Cost. For purposes of this Plan of Administration, the net present value of the overall cost of building and operating a grid-scale solar photovoltaic generating plant, or the net present value of the overall cost to APS of an executed solar photovoltaic PPA, over the economic life of the asset and converted to equal annual amounts.

Line Losses. Electric energy lost as it is transmitted from a supply source (i.e., an electric generation plant) to a delivery point (i.e., the Customer's residence or place of business).

Partial Requirements Service. Electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).

Production Tax Credit. The income tax credit available in the State of Arizona for taxpayers that own a qualified renewable energy generator as defined in A.R.S. §43-1083.02 and §43-1164.03 that produces energy after December 31, 2010 and before January 1, 2021. The amount of Production Tax Credit available is limited by facility and by calendar year.

Revenue Requirement. For purposes of this Plan of Administration, the amount of revenue calculated to be recovered in rates for the APS-owned grid-scale solar facilities included in the RCP calculation. Revenue Requirement expenses include depreciation expense, income taxes, property taxes, deferred taxes and tax credits where appropriate, associated operation and maintenance expense, and an approved debt and equity return.

5. System Eligibility

A distributed generation facility must meet all of the following qualifications to be eligible for the RCP:

- Electricity must be generated using solar photovoltaic panels;
- The facility must be interconnected to the Company's distribution grid;
- The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;
- The facility's nameplate capacity cannot be larger than the following electrical service limits:
 - a. For 200 Amp service, a maximum of 15 kW-dc,
 - b. For 400 Amp service, a maximum of 30 kW-dc,
 - c. For 600 Amp service, a maximum of 45 kW-dc,
 - d. For 800 Amp service and above, a maximum of 60 kW-dc; and



PLAN OF ADMINISTRATION RESOURCE COMPARISON PROXY

- For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).

SPECIAL CASES

Switching from a grandfathered legacy solar rate. A Customer may switch from a grandfathered solar Legacy rate and net metering rider to a new retail rate and the RCP rider. However, they will lose their grandfathering status and may not subsequently switch back to the grandfathered rate or net metering program. In addition, the Customer will not be eligible for an initial 10-year lock in the purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

Increasing Capacity. If a Customer modifies their generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this Plan of Administration, a material increase in capacity means increasing the capacity by 10% or 1 kW, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase their system's capacity by a total of 10% or 1 kW, whichever is greater.

Transferring Service. If a Customer moves to a site that is currently being served under rate rider RCP they will continue service under the rider with the same rate tranche. If a Customer moves their solar system to another site they will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

6. Calculation of Resource Comparison Proxy Purchase Rate

The RCP is calculated by developing a historical rolling five-year weighted average cost per kWh for all grid-scale renewable solar photovoltaic generating systems used by APS to serve its customers, both APS-owned facilities and facilities from which APS purchases power through an executed PPA. The calculation methodology is as follows:

The first RCP effective on July 1, 2017 is \$0.12900/kWh, using 2015 as the Base Year inclusive of adjustments as provided for in Decision No. xxxxx. Subsequent RCPs derived from following the calculations in Steps 1 through 8 below will then be compared to the RCP in effect. If the calculated RCP results in a reduction in the purchase rate from the previous RCP, any such reduction will be no greater than 10% of the previous RCP.

1. Determine appropriate five-year period. The RCP will be calculated using the 5-year period with the Base Year as the final year of the five. Only those grid-scale solar facilities with an in-service date within this 5-year period will be included in the annual RCP calculation.



PLAN OF ADMINISTRATION RESOURCE COMPARISON PROXY

If there are no grid-scale solar photovoltaic projects in any particular year of the rolling five-year period described above, the rolling 5 year average will be calculated without a project for that particular year. Calculating the RCP without a project for a particular year (i) is the product of the settlement approved in Decision No. xxxx; (ii) is the product of compromise; (iii) does not establish a precedent for how the RCP should be calculated; and (iv) will be revisited in APS's next general rate case.

2. Develop/update annual Revenue Requirement for each APS-owned facility. The Company will calculate revenue requirements for each grid-scale solar photovoltaic generation facility owned by the Company that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual designed output of the facility, including degradation, will be used for this calculation. This step provides an annual revenue requirement cost in dollars for each year of the facility's depreciable life.

3. Incorporate applicable Production Tax Credit. All expected available annual Production Tax Credit tax savings (in dollars) for the above APS facilities will be calculated based on expected annual energy production and subtracted from the annual facility cost derived in Step 2 above for each year.

4. Develop/update annual cost of power from each PPA facility. The Company will calculate an annual cost of purchased power for each facility from which APS purchases power under an executed agreement that qualifies for inclusion in the RCP calculation as determined in Step 1. The annual cost for each of these facilities will be calculated separately for the contract life of each PPA using the contract price and the designed output, including degradation, of the facilities, including contractual escalation factors, as appropriate.

5. Calculate individual facility Levelized Cost. The Levelized Cost for each of the facilities will then be calculated using the data derived in Steps 2 through 4 above. The net present value discount rate used in the Levelized Cost calculations will be calculated using the approved after-tax weighted average cost of capital as determined in the Company's most recent rate case. The result of this calculation step will be a Levelized Cost per MWh for each of the facilities.

6. Calculate weighted Levelized Cost for each facility. The weighted Levelized Cost is calculated by multiplying the cost per MWh derived for each facility in Step 5 by the actual Base year energy production in MWh for each Step 5 facility. The result of this step is an annual weighted cost in dollars for each included facility.

7. Calculate weighted average Levelized Cost for all facilities. The annual weighted average Levelized Cost is determined by dividing the total annual weighted costs for all included facilities by the total Base year energy production MWh. The result of this step is the rolling historical five-year weighted average Levelized Cost per MWh for grid-scale solar photovoltaic facilities on the APS system before any applicable adjustments.

8. Adjustments. An adjustment is then applied to the annual weighted average Levelized Cost per MWh for avoided transmission capacity cost, avoided distribution capacity cost, and line



PLAN OF ADMINISTRATION RESOURCE COMPARISON PROXY

losses as required in Decision No. 75859. For purposes of this Plan of Administration, and subject to future Commission proceedings, the combined adjustment for these three values is set at \$0.02/kWh as provided for in Decision No. xxxxx. This amount is negotiated, does not reflect an actual calculation of system conditions, and establishes no precedent for any future RCP or avoided cost calculations. While future Commission proceedings may establish methodologies for calculation of the adjustments, no changes will be made to this value until the conclusion of the next APS general rate case.

7. Procedural Timeline

The Company will provide Commission Staff and other intervening parties with its annual RCP calculation no later than March 1 each year. Interested parties will file comments to the Company's RCP calculation by April 1. Commission Staff will file its Report by May 15 and request that Staff's Report be considered in the June Open Meeting and be approved so that the new RCP calculation is effective on July 1.

8. Confidential Data

Portions of the data used to calculate APS's annual RCP are competitively/highly confidential and cannot be released to the public. Competitively/highly confidential information will be made reasonably accessible to parties so that they may determine that such data supports the RCP calculation and that the RCP calculation complies with Commission orders. Competitively/highly confidential information includes cost and production data for facilities from which APS purchases energy under a PPA agreement.

9. Schedules

Templates of the spreadsheet used to calculate the RCP are attached:

- Schedule 1: Annual Resource Comparison Proxy Calculation Summary
- Schedule 2: Solar Photovoltaic Grid-Scale Plant Data and Levelized Cost
- Schedule 3: Individual Plant Annual Cost (\$/MWh)
- Schedule 4: Individual Plant Energy Production (MWh)
- Schedule 5: Individual Plant Revenue Requirement/PPA Annual Cost (\$000)
- Schedule 6: Individual Plant Revenue Requirement/PPA Annual Cost including Production Tax Credits (\$000)

Each of these schedules contains competitively/highly confidential PPA data as indicated.

Schedule 1: Annual Resource Comparison Proxy Calculation Summary

= Competitively/Highly Confidential

		Competitively/Highly Confidential			Competitively/Highly Confidential		
Year	Project #	Projects	Cost per MWh	1st Year Energy	Weight	Weighted Energy	Weighted Cost (1,000's)
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
	1						
	2						
	3						
	4						
	5						
			Weighted Cost Energy Average Cost per MWh Grid Scale Adjustment Cost per MWh after Grid-Scale Adjustment Trans, Dist, and Losses Adjustment Final Resource Comparison Proxy (RCP)				

Project	RFP Year	Start Date	Start Year	Levelized Cost (Base Year)	GWH (1st Year)

= Competitively/Highly Confidential

Discount Rate		<div> <div></div> <div>= Competitively/Highly Confidential</div> </div>	BY YEAR: 2011 through 2046
Project	Levelized Energy		

Arizona Public Service Company
Schedule 5: Individual Plant Revenue Requirement/PPA Annual Cost (\$000)
Competitively/Highly Confidential
Page 5 of 6

Discount Rate		
Project	Levelized Cost	
		<div></div> = Competitively/Highly Confidential BY YEAR: 2011 through 2046



**RATE RIDER RCP
PARTIAL REQUIREMENTS SERVICE FOR
NEW ON-SITE SOLAR DISTRIBUTED GENERATION
RESOURCE COMPARISON PROXY EXPORT RATE**

AVAILABILITY

This rate rider is available to partial requirements customers with qualified on-site solar generation, served under an applicable residential rate. This rate rider may not be used in conjunction with a grandfathered residential Legacy rate schedule or Legacy rate rider.

DESCRIPTION

A Customer with solar generation exports power to the grid from time to time when their generation exceeds the load in their home. The Company will meter this export power on an instantaneous basis and provide a monthly bill credit based on the purchase rate in this schedule.

The purchase rates will be determined as follows:

- a. An RCP rate will be determined for each annual tranche of new DG Customers, effective July 1 each year without proration. The RCP rate may not be reduced by more than 10% each year.
- b. Each Customer's bill credit will initially be based on the RCP in effect at the time they submit an interconnection application for their system before July 1 provided that they subsequently complete the installation and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application unless, through no fault of the Customer or the Customer's installer, the interconnection is delayed by a third party or APS. In that circumstance, the Customer will have 270 days to complete their interconnection.
- c. Each Customer's initial RCP rate will be applicable for 10 years from the time of their interconnection.
- d. After each Customer's initial 10 year period the bill credit will be based on the purchase rate in effect at that time, and may change from year to year.

Further details are provided in the Resource Comparison Proxy Plan of Administration and Arizona Corporation Commission Decisions No. 75859 and xxxxx.



**RATE RIDER RCP
PARTIAL REQUIREMENTS SERVICE FOR
NEW ON-SITE SOLAR DISTRIBUTED GENERATION
RESOURCE COMPARISON PROXY EXPORT RATE**

PURCHASE RATES

The Company will provide a bill credit for the exported energy based on the following purchase rates:

Tranche 2017	July 1, 2017 through June 30, 2018	\$0.1290	per kWh
Tranche 2018	July 1, 2018 through June 30, 2019	TBD	per kWh

Any bill credit in excess of the Customer's otherwise applicable monthly bill will be credited on the next monthly bill, or subsequent bills if necessary. After the Customer's December bill, a Customer may request a check for any outstanding credits from the prior year; however, if the outstanding credits exceed \$25, the Company will automatically issue a check to the Customer. Otherwise, the bill credits will carry forward to the following year.

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. Electricity must be generated using solar photovoltaic panels;
2. The generator must be interconnected to the Company's distribution grid;
3. The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;
4. The facility's nameplate capacity cannot be larger than the following electrical service limits:
 - a. For 200 Amp service, a maximum of 15 kW-dc.
 - b. For 400 Amp service, a maximum of 30 kW-dc.
 - c. For 600 Amp service, a maximum of 45 kW-dc.
 - d. For 800 Amp service and above, a maximum of 60 kW-dc; and
5. For systems over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).



**RATE RIDER RCP
PARTIAL REQUIREMENTS SERVICE FOR
NEW ON-SITE SOLAR DISTRIBUTED GENERATION
RESOURCE COMPARISON PROXY EXPORT RATE**

SPECIAL CASES

1. Switching from a grandfathered legacy solar rate. A Customer may switch from a grandfathered solar Legacy rate and net metering rider to a new retail rate and the RCP rider. However, they will lose their grandfathering status and may not subsequently switch back to the grandfathered rate or net metering program. In addition, the Customer will not be eligible for an initial 10-year lock in the purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.
2. Increasing Capacity. If a Customer modifies their generation system to include a material increase in capacity they will no longer be eligible for the initial RCP purchase rate they locked in for ten years; rather their bill credits will be based on the current RCP rate locked in for a period of ten years minus the number of years they received service under a prior RCP rate. For purposes of this rate rider, a material increase in capacity means increasing the capacity by 10% or 1 kW, whichever is greater. Over the term of the Customer's ten year RCP lock, they may only increase their system's capacity by a total of 10% or 1 kW, whichever is greater.
3. Transferring Service. If a Customer moves to a site that is currently being served under rate rider RCP they will continue service under the rider with the same rate tranche. If a Customer moves their solar system to another site they will no longer be eligible for the initial 10-year lock in the RCP purchase rate; rather their bill credits will be based on the annual RCP rate as it changes from year to year.

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.
2. The Customer must have a standard Advanced Metering Infrastructure (AMI) meter installed to measure the production from their solar generation system as well as an AMI meter for electrical service.
3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a Customer's interconnection agreement.
4. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).



**RATE RIDER EPR-6
PARTIAL REQUIREMENTS SERVICE FOR
ON-SITE RENEWABLE DISTRIBUTED GENERATION
NET METERING**

AVAILABILITY

This rate rider is available to qualifying residential and non-residential partial requirements Customers with an on-site renewable distributed generation system. Residential Customers with an interconnected on-site solar photovoltaic system are not eligible for this rate rider.

DESCRIPTION

This rate rider describes how the Company will bill a Customer who participates in the Company's net metering program and exports energy through the Company's distribution grid. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

Under this rider, export energy (kWh) will be netted against kWh supplied by the Company during the billing month, or banked and netted on a subsequent bill if necessary.

If a Customer is served under a time-of-use rate, the export energy will be netted according to the on-peak and off-peak periods. On-peak export energy will be netted against on-peak energy from the Company and off-peak export energy will be netted against off-peak energy, for all unbundled components of the rate that have time-of-use charges.

PURCHASE RATES

After the December bill, any export energy that has not already been netted on a bill will be acquired by the Company in exchange for a monetary bill credit based on the following purchase rate:

\$0.02895	per kWh
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The purchase rate is based on the Company's near-term avoided costs and is revised from time to time.

BILLING DETAILS

1. All terms and charges in the customer's rate schedule continue to apply to electric service provided under this rider.
2. If the Customer terminates electric service, the Company will issue a check for any remaining export energy at the purchase price.



**RATE RIDER EPR-6
PARTIAL REQUIREMENTS SERVICE FOR
ON-SITE RENEWABLE DISTRIBUTED GENERATION
NET METERING**

GENERATOR REQUIREMENTS

Distributed generators must meet all of the following qualifications:

1. The generator must be interconnected to the Company's distribution grid;
2. The generator must be on-site, installed behind the billing meter, and must serve the Customer's load;
3. For qualifying residential facilities, the nameplate capacity cannot be larger than the following electrical service limits:
 - a. For 200 Amp service, a maximum of 15 kW-dc.
 - b. For 400 Amp service, a maximum of 30 kW-dc.
 - c. For 600 Amp service, a maximum of 45 kW-dc.
 - d. For 800 Amp service and above, a maximum of 60 kW-dc; and
4. For all qualifying residential and non-residential facilities over 10 kW-dc, the facility's nameplate capacity cannot be larger than 150% of the customer's maximum one-hour peak demand measured in AC over the prior twelve (12) months. (For example, if the customer's peak is 8kW-ac, the maximum system size that could be installed would be 12kW-dc).

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.
2. The Customer must have an Advanced Metering Infrastructure (AMI) meter, or equivalent, installed to measure the production from their solar generation system as well as an AMI meter for electrical service.
3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a customer interconnection agreement.
4. A Net Metering Facility is an on-site distributed generation system that:
 - a. Provides part of the Customer's energy requirements at the site where the system is installed;
 - b. Uses renewable resources, as defined by the Arizona Corporation Commission, including a fuel cell with the chemical reaction derived from renewable resources



**RATE RIDER EPR-6
PARTIAL REQUIREMENTS SERVICE FOR
ON-SITE RENEWABLE DISTRIBUTED GENERATION
NET METERING**

-
- or a combined heat and power (CHP) facility as defined by A.A.C. R14-2-2302, to generate energy; and
- c. Is interconnected to and can operate in parallel and in phase with the Company's existing distribution system.
5. Partial Requirements Service is electric service provided to a Customer that has an on-site distributed generation system interconnected to the Company's distribution grid that is configured so that the energy generated first supplies its own electric requirements, and any excess generation (over and above its own requirements at any point in time) is then exported to the Company. The Company supplies the Customer's supplemental electric requirements (those not met by their own generation facilities).



**RATE RIDER LEGACY EPR-6
PARTIAL REQUIREMENTS SERVICE FOR
ON-SITE RENEWABLE DISTRIBUTED GENERATION
NET METERING**

AVAILABILITY

This rate rider is available to Customers that qualify for the residential solar grandfathering program. It may be used in conjunction with the residential Legacy rate schedules for distributed generation systems.

This rate rider is frozen effective July 1, 2017. This means a residential Customer that is already taking service under this rate rider by that date may continue service under the terms of the grandfathering program. Other residential Customers must meet the qualification requirements of the grandfathering program to take service under this schedule.

A residential Customer may remain on this rate rider for up to 20 years from the date their solar generator was interconnected to the Company's distribution grid. After that time, the residential Customer will not be eligible for a grandfathered solar Legacy rate or this rate rider. Instead, the residential Customer will be served under an applicable retail rate of their choice and Rate Rider RCP, or a subsequent replacement rider.

DESCRIPTION

This rate rider describes how the Company will bill a Customer who participates in the Company's net metering program. A partial requirements Customer has on-site generation that serves some of their electrical requirements and relies on the Company for additional electrical services. Export energy occurs when the Customer's generation is greater than their electrical load in any instant and this excess energy flows back to the Company's grid.

Under this rider, export energy (kWh) will be netted against kWh supplied by the Company during the billing month, or banked and netted on a subsequent bill if necessary.

If a Customer is served under a time-of-use rate, the export energy will be netted according to the on-peak and off-peak periods, i.e. on-peak export energy will be netted against on-peak energy from the Company and vice-versa, for all unbundled components of the rate that have time-of-use charges.

PURCHASE RATES

After the December billing cycle, any export energy that has not already been netted on a bill will be acquired by the Company in exchange for a monetary bill credit based on the following purchase rate:

\$0.02895	per kWh
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The purchase rate is based on the Company's near-term avoided costs and is revised from time to time.



**RATE RIDER LEGACY EPR-6
PARTIAL REQUIREMENTS SERVICE FOR
ON-SITE RENEWABLE DISTRIBUTED GENERATION
NET METERING**

BILLING DETAILS

1. All terms and charges in the Customer's rate schedule, other than those specifically included here, continue to apply to electric service provided under this rider.
2. If the Customer terminates electric service, the Company will issue a check for the remaining export energy at the purchase price.

RESIDENTIAL GRANDFATHERING PROGRAM

The terms and conditions for the solar grandfathering program for residential Customers are as follows:

1. Existing solar customers with systems interconnected to the Company's distribution grid prior to July 1, 2017 and otherwise qualify for this rate rider may continue service under the grandfathering program.
2. Customers who (i) submit a complete application for interconnection to the Company by July 1, 2017; (ii) include in their interconnection application a fully executed sales or lease contract for their rooftop solar system; and (iii) install their rooftop solar system and obtain approval by the appropriate Authority Having Jurisdiction within 180 days of their interconnection application, and otherwise qualify for this rate rider may take service under the grandfathering program. If the interconnection is delayed by a third party or APS through no fault of the Customer or the Customer's installer, the Customer will have 270 days to complete their interconnection.
3. The grandfathering period will be 20 years from the customer's initial interconnection date and applies to the site where the system is located.
4. Over the term of the grandfathering period, a Customer may not increase the capacity of their grandfathered solar generation unit by more than a total of 10% or 1 kW, whichever is greater.
5. Customers may not move their solar generation unit to another site.
6. The grandfathering may be transferred to a new customer purchasing the home.
7. The Customer may remain on their current Legacy rate schedule but may not move between alternate grandfathered Legacy rate schedules.
8. The Customer will be subject to changes in annual adjustor rates including the rate structure and level.



**RATE RIDER LEGACY EPR-6
PARTIAL REQUIREMENTS SERVICE FOR
ON-SITE RENEWABLE DISTRIBUTED GENERATION
NET METERING**

-
9. Frozen Rate Rider Legacy LFCR-DG will continue to apply.
10. A Customer may leave the grandfathering program and be served under a non-Legacy rate schedule. However, the Customer may not subsequently return to the grandfathering program at a later date.

SERVICE DETAILS

1. All terms and charges in the Customer's retail rate schedule continue to apply.
2. The Customer must have an Advanced Metering Infrastructure (AMI) meter, or equivalent, installed to measure the production from their solar generation system as well as an AMI meter for electrical service.
3. The Company provides service under this rider in accordance with its Interconnection Requirements Manual. Service terms and conditions may be included in a customer interconnection or purchase agreement.
4. A Net Metering Facility is an on-site distributed generation system that:
 - a. Provides part of the Customer's energy requirements at the site where the system is installed;
 - b. Uses renewable resources, as defined by the Arizona Corporation Commission, to generate energy; and
 - c. Is interconnected to and can operate in parallel and in phase with the Company's existing distribution system.

Appendix I



**RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)**

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 401 kW and greater that do not qualify for Rate Schedules E-34 or E-35.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter).

The Company will place the Customer on the applicable Rate Schedule E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

Summer season: May through October billing cycles
Winter season: November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charges (only one applies)		
For service through Self-Contained Meters	\$3.060	per day
For service through Instrument-Rated Meters	\$3.920	per day
For service at Primary Voltage	\$6.847	per day
For service at Transmission Voltage	\$38.695	per day

Demand Charges (only one set applies)			
Secondary	First 100 kW	\$25.372	per kW
	All additional kW	\$17.605	per kW
Primary	First 100 kW	\$23.049	per kW
	All additional kW	\$16.411	per kW
Transmission	First 100 kW	\$17.624	per kW
	All additional kW	\$11.753	per kW



**RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)**

	Summer	Winter	
Energy Charge	\$0.05540	\$0.03712	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	\$2.404	per day
Meter Reading	\$0.009	per day
Billing	\$0.030	per day
Metering* (only one applies)		
Self Contained Meters	\$0.617	per day
Instrument-Rated Meters	\$1.477	per day
Primary	\$4.404	per day
Transmission	\$36.252	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission	\$2.870	per kW
Generation	\$5.496	per kW
Delivery - Secondary	First 100 kW	\$17.006 per kW
	All additional kW	\$9.239 per kW
Delivery - Primary	First 100 kW	\$14.683 per kW
	All additional kW	\$8.045 per kW
Delivery - Transmission	First 100 kW	\$9.258 per kW
	All additional kW	\$3.387 per kW

Energy Charge Components

System Benefits	\$0.00276	per kWh
Delivery	\$0.00000	per kWh

	Summer	Winter	
Generation	\$0.05264	\$0.03436	per kWh



**RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)**

For billing purposes, the kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period (or other period as specified by an individual customer contract) of maximum use during the month, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8.
2. 80% of the highest kW measured during the six (6) summer billing months (May-October) of the twelve (12) months ending with the current month.
3. The minimum kW specified in the agreement for service or individual contract.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

AGGREGATION OPTION

Customers with multiple accounts served under Rate Schedule E-32 L or E-32TOU L that together have a combined load of at least 5 MW are eligible for a discount of \$0.0024 per kWh for the unbundled Generation charge in this rate schedule. All other charges of this schedule apply as shown. Customers must execute a contract with the Company specifying eligible accounts prior to receiving this discount. Customer accounts served under Rate Rider PPR, Rate Rider E-56, or Rate Rider E-56R or have on-site generation greater than 100 kW-AC are not eligible for this option.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Tax Expense Adjustment Charge, Adjustment Schedule TEAM.
7. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.



**RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)**

8. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements – Net Billing
EPR-6	Partial Requirements – Solar Net Metering
E-56	Partial Requirements Service
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.
2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.
3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of $\pm 95\%$.
4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.
5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its customers, and they have provisions and charges that may affect the customer's bill (for example, service connection charges).



RATE SCHEDULE E-32 L
LARGE GENERAL SERVICE (401 kW +)

2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
3. Electric service is supplied at a single point of delivery and measured through a single meter.
4. Direct Access customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the customer at the charges shown above.



**RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE**

AVAILABILITY

This rate schedule is available to non-residential Customers with monthly loads of 401 kW and greater that do not qualify for Rate Schedule E-35.

DESCRIPTION

This rate has three parts: a basic service charge, a demand charge for the highest amount of demand (kW) averaged in a 15-minute period for the month, and an energy charge for the energy (kWh) used during the month. The energy charge will vary by season (summer or winter) and time of day (On-Peak and Off-Peak).

The Company will place the Customer on the applicable Rate Schedule Time-of-Use E-32 XS, E-32 S, E-32 M, or E-32 L based on the Customer's average monthly maximum demand, as determined by the Company each year. This determination will be made annually.

TIME PERIOD

On-Peak hours:	3:00 pm - 8:00 pm Monday through Friday
Off-Peak hours:	All remaining hours
Summer season:	May through October billing cycles
Winter season:	November through April billing cycles

CHARGES

The monthly bill will consist of the following charges, plus adjustments:

Bundled Charges

Basic Service Charge (only one applies)		
For service through Self-Contained Meters	\$3.060	per day
For service through Instrument-Rated Meters	\$3.920	per day
For service at Primary Voltage	\$6.847	per day
For service at Transmission Voltage	\$38.695	per day



RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

Demand Charges (only one set applies)			
Secondary	First 100 On-Peak kW	508	per kW
	All additional On-Peak kW	\$11.795	per kW
	First 100 Off-Peak kW	\$6.396	per kW
	All additional Off-Peak kW	\$3.370	per kW
Primary	First 100 On-Peak kW	\$16.936	per kW
	All additional On-Peak kW	\$11.710	per kW
	First 100 Off-Peak kW	\$5.679	per kW
	All additional Off-Peak kW	\$3.272	per kW
Transmission	First 100 On-Peak kW	\$15.916	per kW
	All additional On-Peak kW	\$10.478	per kW
	First 100 Off-Peak kW	\$4.871	per kW
	All additional Off-Peak kW	\$3.137	per kW

Energy Charges			
	Summer	Winter	
On-Peak	\$0.07018	\$0.05552	per kWh
Off-Peak	\$0.05730	\$0.04264	per kWh

Unbundled Components of the Bundled Charges

Bundled Charges consist of the components shown below. These are not additional charges.

Basic Service Charge Components

Customer Accounts Charge	\$2.404	per day
Meter Reading	\$0.009	per day
Billing	\$0.030	per day



RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

Metering* (only one applies)		
Self Contained Meters	\$0.617	per day
Instrument-Rated Meters	\$1.477	per day
Primary	\$4.404	per day
Transmission	\$36.252	per day

*These daily metering charges apply to typical installations. Customers requesting specialized facilities are subject to additional metering charges.

Demand Charge Components

Transmission		\$2.870	per kW
Generation On-Peak		\$5.980	per kW
Generation Off-Peak		\$2.275	per kW
Delivery - Secondary	First 100 On-Peak kW	\$8.658	per kW
	All additional On-Peak kW	\$2.945	per kW
	First 100 Off-Peak kW	\$4.121	per kW
	All additional Off-Peak kW	\$1.095	per kW
Delivery - Primary	First 100 On-Peak kW	\$8.086	per kW
	All additional On-Peak kW	\$2.860	per kW
	First 100 Off-Peak kW	\$3.404	per kW
	All additional Off-Peak kW	\$0.997	per kW
Delivery - Transmission	First 100 On-Peak kW	\$7.066	per kW
	All additional On-Peak kW	\$1.628	per kW
	First 100 Off-Peak kW	\$2.596	per kW
	All additional Off-Peak kW	\$0.862	per kW

Energy Charge Components

System Benefits Charge:	\$0.00276	per kWh
Delivery Charge	\$0.01208	Per kWh



**RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE**

	Summer	Winter	
Generation On-Peak	\$0.05534	\$0.04068	per kWh
Generation Off-Peak	\$0.04246	\$0.02780	per kWh

For billing purposes, the On-Peak kW used in this rate schedule will be the greater of the following:

1. The average kW supplied during the 15-minute period of maximum use during the On-Peak period during the billing period, as determined from readings of the Company's meter or in accordance with the Company's Service Schedule 8.
2. 80% of the highest On-Peak kW measured during the six summer billing months (May-October) of the twelve (12) months ending with the current month.
3. The minimum kW specified in the agreement for service or individual contract.

Off-peak kW will be based on the average kW supplied during the 15-minute period of maximum use during the Off-peak hours of the billing period, as determined from readings of the Company's meter.

The monthly bill for service under this rate schedule will not be less than the Bundled Basic Service Charge plus the Bundled Demand Charge for each kW.

AGGREGATION OPTION

Customers with multiple accounts served under Rate Schedule E-32 L or E-32TOU L that together have a combined load of at least 5 MW are eligible for a discount of \$0.0024 per kWh for the unbundled Generation charge in this rate schedule. All other charges of this schedule apply as shown. Customers must execute a contract with the Company specifying eligible accounts prior to receiving this discount. Customer accounts served under Rate Rider PPR, Rate Rider E-56, or Rate Rider E-56R or have on-site generation greater than 100 kW-AC are not eligible for this option.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.



**RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE**

3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
6. The Tax Expense Adjustment Charge, Adjustment Schedule TEAM.
7. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
8. Any applicable taxes and governmental fees that are assessed on APS's revenues, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

PPR	Preference Power
CPP-GS	Critical Peak Pricing
EPR-2	Partial Requirements - Net Billing
EPR-6	Partial Requirements - Solar Net Metering
E-56	Partial Requirements
E-56R	Partial Requirements - Renewable
GPS-1, GPS-2, GPS-3	Green Power
SGSP (Frozen)	Schools and Government Solar Program

POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.
2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.
3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of $\pm 95\%$.



RATE SCHEDULE E-32TOU L
LARGE GENERAL SERVICE (401 kW +)
TIME OF USE

4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.
5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).
2. Electric service provided will be single-phase, 60 Hertz at APS's standard voltages available at the Customer site. Three-phase service is required for motors of an individual rated capacity of 7 ½ HP or more.
3. Electric service is supplied at a single point of delivery and measured through a single meter.
4. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by APS and billed to the Customer at the charges shown above.



**RATE SCHEDULE XHLF
GENERAL SERVICE
EXTRA HIGH LOAD FACTOR**

AVAILABILITY

This rate schedule is available to Customers whose monthly maximum demand is 5,000 kW or more with a load factor of 92% or more for a minimum of nine months of the prior 12 month period.

Customers will be required to execute a service agreement or contract that specifies certain provisions of their electric service, such as a contract length, minimum and maximum monthly loads, special charges, and other service details.

Qualifying Customers with monthly demands of 15,000 kW and greater may choose to be served with transmission level service by providing the Company with a contribution in aid of construction (CIAC) in lieu of purchasing transmission level facilities. The Customer will be required to execute a maintenance contract and share in the cost of replacement facilities. Under this option, the Company may also finance the CIAC at the Company's weighted average cost of capital established in its most recent rate case. This financing period will not exceed 10 years.

DESCRIPTION

This rate has three parts: a basic service charge, a demand (kW) charge consisting of the average kW supplied during the 15-minute period of maximum use during the billing period, and an energy (kWh) charge for the energy used for the entire month.

Monthly load factor will be established using the formula:

$$\text{Monthly Load Factor} = \frac{\text{Billed kWh}}{(\text{billed kW} * \text{Billing Days} * 24 \text{ hours})}$$

CHARGES

The monthly bill will be calculated at the following rates or the minimum rates, whichever is greater, plus any adjustments incorporated in this rate schedule:

Bundled Service

Customers Served at Secondary Voltage		
Basic Service Charge	\$5.122	per day
Demand Charge	\$17.950	per kW
Energy Charge	\$0.03761	per kWh



**RATE SCHEDULE XHLF
GENERAL SERVICE
EXTRA HIGH LOAD FACTOR**

Customers Served at Primary Voltage		
Basic Service Charge	\$8.049	per day
Demand Charge	\$16.609	per kW
Energy Charge	\$0.03761	per kWh

Customers Served at Transmission Voltage		
Basic Service Charge	\$39.897	per day
Demand Charge	\$12.917	per kW
Energy Charge	\$0.03761	per kWh

Unbundled Standard Offer Service

Bundled Charges consists of the Components shown below. These are not additional charges.

Basic Service Charge Components		
Customer Accounts	\$3.606	per day
Meter Reading	\$0.009	per day
Billing	\$0.030	per day
Meter (only one applies)		
Instrument-Rated Meter	\$1.477	per day
Primary Meter	\$4.404	per day
Transmission Meter	\$36.252	per day
Demand Charge Components		
Transmission Charge	\$3.236	per kW
Generation - Capacity	\$9.274	per kW
Delivery (only one applies)		
Secondary Service	\$5.440	per kW
Primary Service	\$4.099	per kW
Transmission Service	\$0.407	per kW
Energy Charge Components		
Generation - Fuel	\$0.03485	per kWh
System Benefits	\$0.00276	per kWh



**RATE SCHEDULE XHLF
GENERAL SERVICE
EXTRA HIGH LOAD FACTOR**

The kW for billing will be the greater of:

- a. The average kW supplied during the 15-minute period of maximum use during the monthly billing period; or
- b. The minimum kW specified in a service agreement.

MINIMUM BILL

The bill will not be less than the minimum amount specified in the Customer's service agreement or contract.

ADJUSTMENTS

The bill will include the following adjustments:

1. The Renewable Energy Adjustment Charge, Adjustment Schedule REAC-1.
2. The Power Supply Adjustment charges, Adjustment Schedule PSA-1.
3. The Transmission Cost Adjustment charge, Adjustment Schedule TCA-1.
4. The Environmental Improvement Surcharge, Adjustment Schedule EIS.
5. Direct Access Customers returning to Standard Offer service may be subject to a Returning Customer Direct Access Charge, Adjustment Schedule RCDAC-1.
6. The Demand Side Management Adjustment charge, Adjustment Schedule DSMAC-1.
7. The Tax Expense Adjustment charge, Adjustment Schedule TEAM.
8. Any applicable taxes and governmental fees that are assessed on APS's revenue, prices, sales volume, or generation volume.

RATE RIDERS

Eligible rate riders for this rate schedule are:

GPS-1, GPS-2, GPS-3	Green Power
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POWER FACTOR REQUIREMENTS

1. The Customer's load must not deviate from phase balance by more than 10%.



**RATE SCHEDULE XHLF
GENERAL SERVICE
EXTRA HIGH LOAD FACTOR**

2. Customers receiving service at voltage levels below 69 kV must maintain a power factor of 90% lagging. The power factor cannot be leading unless the Company agrees.
3. Customers receiving service at voltage levels of 69 kV or above must maintain a power factor of $\pm 95\%$.
4. The Company may install certain monitoring equipment to test the Customer's power factor. If the load doesn't meet the requirements the Customer will pay the cost to install and remove the equipment.
5. If the load does not meet the power factor requirements the Customer must resolve the issue. Otherwise, the Customer must pay for any costs incurred by the Company for investments on its system necessary to address the issue. Also, until the problem is remedied, the Company may compute the Customer's monthly billing demand with kVA instead of kW.

SERVICE DETAILS

1. The type of service provided under this schedule will be three phase, 60 Hertz, at the Company's standard voltages that are available within the vicinity of the Customer site.
2. Daily metering charges apply to typical installations. Customers requiring specialized Equipment may incur additional metering charges that reflect the additional cost.
3. Customers that self-provide some of their electrical requirements from on-site generation will be billed according to one of the partial requirement rate riders.
4. Electrical service must be supplied at one point of delivery and measured through one meter unless otherwise specified in a service agreement.
5. This schedule is not applicable to breakdown, standby, supplemental, residential or resale service.
6. Direct Access Customers who purchase available electric services from a supplier other than APS may take service under this schedule. The bill for these Customers will only include the Unbundled Component charges for Customer Accounts, Delivery, System Benefits, and any applicable Adjustments. If metering and billing services are not available from another supplier, those services will be provided by the Company and billed to the Customer at the charges shown above.
7. APS provides electric service under the Company's Service Schedules. These schedules provide details about how the Company serves its Customers, and they have provisions and charges that may affect the Customer's bill (for example, service connection charges).

Appendix J



SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE
INDUSTRIAL DEVELOPMENT PLAN

General Description

This Service Schedule provides the Terms and Conditions under which Arizona Public Service Company (APS or Company) may offer financial incentives to potential new commercial or industrial Customers or to existing commercial and industrial Customers who are adding significant new load.

Availability of this schedule is limited to the lesser of 100 MW of new and additional load or 50 new Customers.

The Customer must provide all requested information to the Company in order to demonstrate eligibility. The Company will evaluate all relevant information and will determine whether to offer the Customer an incentive.

Consistent with the Schedule, when the Company determines that it is appropriate to offer an incentive to an eligible Customer, an agreement will be executed with the Customer. The agreement will specify the incentive and other terms where different from the Company's other Service Schedules.

APS will file each agreement, along with a complete Customer Characteristics Report with Arizona Corporation Commission (Commission) Staff as a compliance filing. Each agreement filed with the Commission Staff will become effective 30 days after filing.

Any Customer information that the Company provides to Commission Staff on a confidential basis will be returned to the Company no later than 60 days after an application under this Schedule is filed.

1. Eligibility Criteria

The Company will evaluate the following Customer characteristics prior to offering service under this Schedule to determine if the Customer is eligible for a financial incentive:

1.1 Availability of Alternative Locations

- (A) Incentives are available only to Customers who have not located or expanded in the Company's service area before the Commission's review of the application and who would not locate or expand in the Company's service area without this Schedule's incentive.
- (B) The Customer must provide the Company with evidence that additional locations, outside the Company's service area, have been considered for location or expansion. This evidence must consist of written documentation including, but not



SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE
INDUSTRIAL DEVELOPMENT PLAN

limited to, detailed quantitative analyses performed by the Customer or consultants regarding the suitability of alternative locations.

- (C) Based on the information provided, the Company will determine whether the Customer would reasonably locate elsewhere in the absence of the incentive. If so, the Customer will be deemed to have met this requirement.

1.2 Effects on Competitors

- (A) Incentives will be available to the Customer only when existing Customers in the same line of business and market are not adversely impacted by the discounted rates.
- (B) The Customer must provide a detailed description of goods and services produced, the technology employed, and the market(s) the Customer serves.
- (C) Based on the provided information, along with knowledge of its customer base, the Company must reasonably verify that this requirement is satisfied for the Customer to be eligible for an incentive.

1.3 Customer Load Requirements

- (A) To qualify for this Schedule, electric requirements for a new Customer must be at least 2 MW and existing Customers must add at least 1 MW of load. To determine Customer load, APS will consider both energy purchased from the Company and any energy generated by the Customer using cogeneration or small power production facilities.
- (B) The Customer's monthly average load factor must be 55% or greater. This load factor criteria may be waived if one of the following apply:
1. The Customer's daily off-peak energy usage in kWh is greater than 50% of total monthly energy usage in kWh (off-peak hours will be defined using the applicable General Service Rate Schedule); or
 2. The Customer's new or added load is interruptible and the Customer's peak load is at least 3 MW.
- (C) Loads that do not operate in the summer months of June through September will be given special consideration when determining an applicable incentive.
- (D) APS will assist the Customer to consider and employ state-of-the-art, cost-effective energy conservation and demand response measures at its facility. These measures may include efficiency motors, motor control systems, and other general measures such as efficient lighting, space heating and cooling, and insulation.



SERVICE SCHEDULE 9

**CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE
INDUSTRIAL DEVELOPMENT PLAN**

1.4 Economic Requirements

- (A) The load must be economic, as calculated under the Company's current extension policy using standard rates.
- (B) To be eligible for incentives under this schedule, a potential load must bring a significant number of jobs or ancillary business into Arizona. In conjunction with this criterion, capital investment by the Customer may also be considered.
- (C) The Company will give particular consideration to Customers whose electric bills exceed 5% of their operating expenses.

2. Conflict of Interest.

2.1 In order to limit any potential conflict of interest, APS is required to submit an affidavit to Commission Staff for each Customer under consideration for service under this Service Schedule. This affidavit will include:

- (A) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries, or one who has filled such role within the three-years prior to the effective date of the Customer's agreement, has or had any interest, direct or indirect, with any entity which has provided substantial services, including real estate broker services, to the Customer in connection with a proposed agreement under this Schedule; and
- (B) A statement that no current officer or director of Pinnacle West Capital Corporation or any of its subsidiaries or affiliates has or had any direct or indirect interest in any property owned in whole or in part by the Customer.

2.2 If the affidavit provided by APS is shown to be inaccurate, the Commission will, in future APS rate cases, impute as revenue the difference between the discounted rate and the tariffed rate which would otherwise apply to the Customer for the period during which the discount was in effect.

3. Rate Provisions

3.1 A Customer satisfying the requirements above may receive an incentive to locate in the Company's service territory. The incentive will be a discount from the Customer's otherwise applicable base electric bill (excluding taxes and adjustments).

3.2 The discounted charges will not be below the Company's marginal cost.



SERVICE SCHEDULE 9

CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE
INDUSTRIAL DEVELOPMENT PLAN

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- 3.3 The discount may vary over the term of the Customer agreement.
- 3.4 The discount will not be larger than 25% of the Customer's total energy bill from the Company.
- 3.5 No discount will be provided from the minimum bill as computed under the Customer's otherwise applicable rate.
- 3.6 For current Customers adding load, the discount will apply only to the added load.
- 3.7 Any incentive available under this schedule will be limited to a specific period of six years or less.
- 3.8 The specific discount and the period over which the discount is applied will be determined after full evaluation of the Customer information as determined by the Company.

4. Customer Characteristic Report

Each agreement must be accompanied by a Customer Characteristic Report. The following information will be included in the Customer Characteristics Report:

4.1 General Information

- (A) Customer name
- (B) Customer contact name and address
- (C) Dates of Customer application and Company decision
- (D) New or existing Customer
- (E) Proposed effective date of agreement

4.2 Location Decision

- (A) Customer location
- (B) Description of other locations considered
- (C) Other locations of Customer's operations
- (D) An affidavit from Customer demonstrating that the Customer would not locate or expand in Arizona absent the discounts
- (E) Within ninety (90) days of the effective date of any agreement under this Schedule, the Customer must supply written documentation and analyses substantiating the affidavit provided under 4.2 (D)
- (F) If the requirements of 4.2 (E) are not met within ninety (90) days of approval of the agreement, the agreement will be void



SERVICE SCHEDULE 9
CONDITIONS GOVERNING ECONOMIC INCENTIVES FOR THE
INDUSTRIAL DEVELOPMENT PLAN

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- (G) Proportion of Customer's production and distribution expenses accounted for by electricity, by natural gas and by other energy sources (specify)

4.3 Effects on Competitors

- (A) Nature of business, description and North American Industry Classification System (NAICS) code
- (B) Number of other Customers in same business
- (C) Market area served by Customer
- (D) Description of effects on other Customers

4.4 Load Characteristics

- (A) Size of load
- (B) Annual load factor
- (C) Off-peak operation
- (D) Description of daily load shape
- (E) Seasonality
- (F) Interruptibility
- (G) Permanency of load
- (H) Estimated impact on system peak demand from the new load

4.5 Energy Service Mix

- (A) Use of natural gas and other energy sources
- (B) Description of energy efficiency measures including building design, processing and other
- (C) Feasibility of cogeneration

4.6 Rates

- (A) Applicable rate schedule
- (B) Years discount will be in effect
- (C) Percentage discount by year
- (D) Estimated annual revenues
- (E) Estimated annual incremental electricity production costs
- (F) Support that the agreement meets the terms described in Rate Provisions Section 3.2 and 3.4

4.7 Special Agreement Provisions

- (A) List of special provisions
- (B) Reasons for special provisions

Appendix K



**RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION**

AVAILABILITY

This rate rider schedule is available in all territories served by the Company at all points where facilities of adequate capacity and the required phase and suitable voltage are adjacent to the sites served.

APPLICATION

This rate rider schedule is available for Standard Offer customers who have an Aggregated Peak Load of 10 MW or more and are served under Rate Schedules E-34, E-35, E32-L, or E-32 TOU L. An aggregated group may also include metered accounts that are served under Rate Schedules E-32 M or E-32 TOU M, if the accounts are located on the same premises and served under the same name as an otherwise eligible Customer.

Customers must have interval metering, Advanced Metering Infrastructure, or an alternative in place at all times of service under this schedule. If the Customer does not have such metering, the Company will install the metering equipment at no additional charge. However, the customer will be responsible for providing and paying for any communication requirements associated with the meter, such as a phone line.

All provisions of the customer's applicable rate schedule will apply in addition to this Schedule AG-X, except as modified herein. Total program participation will be limited to 200 MW of customer load, 100 MW of which will be initially reserved for Customers with single-site peak demands of 20 MW or greater and with monthly average load factors above 70% unless not fully subscribed during the solicitation process.

DEFINITIONS

Aggregated Peak Load: The sum of the maximum metered kW for each of the Customer's aggregated metered accounts over the previous 12 months, as determined by the Company and measured at the Customer's meter(s) at the time of application for service under this rate rider schedule.

Standard Generation Service: Power provided by the Company to a retail customer in conjunction with transmission and delivery services, at terms and prices according to a retail rate schedule other than Schedule AG-X.

Customer: A metered account or set of aggregated metered accounts that meet the eligibility requirements for service and enrollment as an aggregated load for service, under this rate rider schedule.

Generation Service Provider: A third party entity that provides wholesale power to the Company on behalf of a Customer. This entity must be legally capable of selling and delivering wholesale power to the Company.



**RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION**

Generation Service: Wholesale power delivered to APS by a Generation Service Provider.

Imbalance Energy: For each Generation Service Provider, Imbalance Energy will be calculated by the Company as the difference between the hourly delivered energy from the Generation Service Provider and the aggregated actual hourly metered load for all Customers that have selected the Generation Service Provider under this rate rider schedule.

Imbalance Service: Calculating and managing the hourly deviations in energy supply for imbalance energy.

Total Load Requirements: The Customer's hourly load including losses from the point of delivery to the Company's transmission system to the Customer's sites for the duration of the contract.

CUSTOMER ENROLLMENT

The Company will establish an initial enrollment period during which Customers can apply for service under this rate rider schedule. If the applications for service are greater than the program maximum amount, then Customers will be selected for enrollment through a lottery process as detailed in the program guidelines, which may be revised from time-to-time during the term of this rate rider schedule. Otherwise, customers may enroll on a first come first serve basis. After the initial lottery, if necessary, customers who enter the program will not be required to participate in a subsequent lottery to remain in the program.

AGGREGATION

Eligible customers may be aggregated if they have the same corporate name, ownership, and identity. In addition, (1) an eligible franchisor customer may be aggregated with eligible franchisees or associated corporate accounts, and (2) eligible affiliate customers may be aggregated if they are under the same corporate ownership, even if they are operating under multiple trade names.

DESCRIPTION OF SERVICES AND OBLIGATIONS

The Customer must apply for service under this rate rider schedule.

The Company will conduct the enrollment process in accordance with the provisions of this rate rider schedule.

The Customer must select a Generation Service Provider to provide Generation Service in accordance with the timeline specified in the program guidelines

The Company must enter into a contract with the Generation Service Provider to receive delivery and title to the power on the Customer's behalf.



**RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION**

The Generation Service Provider must provide to the Company on behalf of the Customer firm power sufficient to meet the Customer's Total Load Requirements for each of the specified metered accounts, and will attest in its contract with the Company that this condition is met. For the purposes of this rate schedule, "firm power" refers to generation resources identified in Western System Power Pool Schedule C or a reasonable equivalent as determined by the Company.

The Company will provide transmission, delivery and network services to the Customer according to normal retail electric service.

The Company will settle with the Generation Service Provider for Imbalance Service and other relevant costs on a monthly basis according to the program guidelines.

The Generation Service Provider must bill the Company the monthly billed amounts for each customer for Generation Service and Imbalance Service according to the program guidelines.

The Company will bill the customer for the Generation Service Provider's charged amounts and remit the amounts to the Generation Service provider.

The customer will be responsible for paying for the cost of the power provided by the Generation Service Provider, as specified in the contract and this rate rider schedule.

APS will not propose a deferral of unmitigated costs resulting from AG-X, if any, and APS will not request recovery of any unmitigated costs resulting from AG-X, if any, in its next rate case.

DELIVERY OF POWER TO THE COMPANY'S SYSTEM

Power provided by the Generation Service Provider must be firm power as defined above and delivered to the Company at the Palo Verde network delivery point, or other point of delivery as agreed to by the Company. The Generation Service Provider is responsible for the cost of transmission service to deliver the power to the Company's delivery point.

SCHEDULING

The Company will serve as the scheduling coordinator. The Generation Service Provider must provide monthly schedules of hourly loads along with day-ahead hourly load deviations from the monthly schedule to the Company according to the program guidelines. Line losses, in the amount of 7%, from the point of delivery to the Customer's sites will be either scheduled or financially settled. Line losses will be modified to reflect transmission voltage service when applicable.

IMBALANCE SERVICE

The Company will provide Imbalance Service according to the terms and provisions below:



**RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION**

- i. Within the range of +/- 15% each hour or +/- 2 MW, whichever is greater, GSPs would pay based on Schedule 4 of APS's OATT which now reflects the terms of the CAISO imbalance charges.
- ii. Greater than 15 % each hour or +/- 2 MW, whichever is greater, in addition to the charges in ii) GSPs would pay a penalty of \$3 per MWh.
- iii. In addition to the imbalance provisions described above, GSPs with 20% of hourly deviations greater than 20% of the scheduled amount occurring in a calendar month will receive a notice of intent to terminate the GSP's eligibility in the program unless remedied. Imbalances of this magnitude and frequency will be deemed "Excessive." Should Excessive imbalances occur again in a subsequent month, within 12 months from the date of the notice, the GSP's eligibility may be terminated. To avoid termination, a GSP must demonstrate to APS that it is operating in good faith to match its resources to its load. In the event of GSP termination, the Customer will be required to secure a replacement GSP within 60 days, and will be subject to the terms listed in "Default of the third party generation provider".

DEFAULT OF THE THIRD PARTY GENERATION PROVIDER

In the event that the Generation Service Provider is unable to meet its contractual obligations, the customer must notify the Company and select another Generation Service Provider within 60 days. Prior to execution of any new power contract, the Company will provide the required power to the customer, which will be charged at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus \$10 per MWh not to be less than \$0 per MWh or at the applicable retail rate at the company's option. In addition, all other provisions of this rate rider schedule will continue to apply.

If the Customer is unable to select another Generation Service Provider within sixty days, the customer will automatically return to Standard Generation Service, and be subject to the conditions below.

RETURN TO COMPANY'S STANDARD GENERATION SERVICE

Customer may return to the Company's Standard Generation Service under their applicable retail rate schedule if: (1) they provide one or more years notice to the Company; or (2) if the Commission terminates the program. Absent one of these conditions, the Company will provide generation service to the Customers under the following conditions. The Company may elect to provide the customer with generation service at the Palo Verde Peak or Off-peak ICE ("Intercontinental Exchange") Day Ahead Power prices or its successor for the power delivery date plus \$10 per MWh for a period of time for the Customer to attain 1 year notice, at which time the Customer returns to the Company's Standard Generation Service under their



**RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION**

applicable retail rate schedule. The returning customer must remain with the Company's Standard Generation Service for at least 1 year.

RATES

All provisions, charges and adjustments in the customer's applicable retail rate schedule will continue to apply except as follows:

1. The generation charges will not apply;
2. Adjustment Schedule PSA-1 will not apply;
3. Adjustment Schedule EIS will not apply; and
4. The applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder will be applied to the customer's bill.

Schedule AG-X charges determined and billed by the Company include:

1. A monthly administrative management fee of \$0.00180 per kWh applied to the customer's billed kWh;
2. A monthly reserve capacity charge of \$5.540 per kW applied to 100% of the customer's billed kW (on-peak for Rate Schedules E-35 and E-32 TOU L);
3. Returning Customer charge, where applicable, as described herein;
4. Generation Service Provider Default charge, where applicable, as described herein.

These charges and other parameters will be re-evaluated in APS's next rate case, including whether AG-X should be evaluated as a separate customer class in the cost of service study.

Schedule AG-X Generation Service and Imbalance Service charges billed by the Company include:

1. Generation Service charges will be charged at a rate within the minimum and maximum limits as follows:
 - a. When the contract provides for pricing that reflects a specific index price, the minimum price will be the specified index minus 35% and the maximum price will be the specified index plus 35%. The determination that a contract is consistent with this provision will be based on the specified index price applicable on the date the contract is executed.



**RATE RIDER AG-X
GENERAL SERVICE
ALTERNATIVE GENERATION**

- b. When the contract provides for a fixed price supply for the term of the contract, the minimum price will be the generation rate of the Customer's applicable retail rate schedule minus 35%, and the maximum price will be the generation rate of the Customer's applicable retail rate schedule plus 35%. If the Customer has more than one otherwise applicable retail rate schedule, the highest applicable retail rate schedule will be used for purposes of the consistency determination. The determination that a contract is consistent with this provision will be based on the Customer's otherwise applicable retail rate schedule in effect on the date the contract is executed.
 - c. Losses from the delivery point to the Customer's meters and charges for transmission and distribution will not be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule, while Capacity Reservation Charge, the Management Fee, and Imbalance Service charges will be included in the Generation Service charge for purposes of determining whether the contract is consistent with the minimum and maximum price provisions of this rate rider schedule.
2. Imbalance Service charges will be charged at a rate greater than \$0.00 per kWh and less than or equal to the rate that the Company charges the Generation Service Provider for Imbalance Service as specified herein.

CONTRACT TERM AND REQUIREMENTS

The term of the contract with the Generation Service Provider must be for not less than one year and must include termination provisions to comply with Section IV under imbalance services, as well as general termination provisions should the program be discontinued at some point in the future.

The Generation Service Provider and Customer will enter into a contract or contracts with the Company, stating the pertinent details of the transaction with the Generation Service Provider, including but not limited to the scheduling of power, location of delivery and other terms related to the Company's management of the generation resource.

CREDIT REQUIREMENTS

A Generation Service Provider or its parent company must have at least an investment grade credit rating or demonstrate creditworthiness in the form of either a 3rd-party guarantee from an investment grade rated company, surety bond, letter of credit, or cash in accordance with the Company's standard credit support rules.

Appendix L

Targets by Class Settlement

	Target	Percent
Settlement revenue increase	94,624,000	3.28%
Application revenue increase	165,883,743	5.74%
ratio	57.0424%	
adjustor transfer	267,953,000	9.28%
Increase base rates (with adjustor transfer)	362,577,000	12.55%
GS - XS,S decrease to spread to non-res	123,826	0.014%
Schools discount	1,206,688	0.086%

Class	Base Rates	Present % COS	Application Requested Increase	Step 1 Settlement Requested Increase	Step 2 Spread GS - XS,S hold	Step 3a Recover Schools Discount	Step 3b Receive Schools Discount	Net Impact Increase	Adjustor Transfers	Target Increase Base Rates	Actual Increase Base Rates
Residential	1,486,577,640	85.9%	7,959%	4.54%	0.00%	0.00%	0.00%	4.54%	11.36%	15.90%	15.90%
GS - XS,S	515,621,307	123.7%	0.042%	0.04%	0.00%	0.09%	-0.04%	0.09%	8.59%	8.68%	8.66%
GS - M	316,428,191	111.9%	4.042%	2.31%	-0.01%	0.09%	-0.17%	2.21%	7.66%	9.86%	9.87%
GS - L	293,386,250	100.5%	6.042%	3.45%	-0.01%	0.09%	-0.07%	3.45%	5.10%	8.55%	8.55%
GS - XL	203,076,401	87.0%	6.142%	3.50%	-0.01%	0.09%	0.00%	3.58%	4.71%	8.28%	8.28%
GS - schools	11,344,975	91.1%	6.042%	3.45%	-0.01%	0.09%	-2.33%	1.19%	9.35%	10.54%	10.54%
GS - worship	4,069,264	62.3%	9.042%	5.16%	-0.01%	0.09%	0.00%	5.23%	11.34%	16.57%	16.77%
Irrigation	28,739,440	93.7%	5.742%	3.28%	-0.01%	0.09%	0.00%	3.35%	11.30%	14.65%	14.66%
Lighting	29,660,294	94.6%	5.742%	3.28%	-0.01%	0.09%	0.00%	3.35%	4.37%	7.71%	7.71%
Total	2,888,903,762	95.0%	5,742%	3,28%	-0.01%	0.09%	0.00%	3,28%	9,28%	12.55%	12.55%

residential	1,486,577,640	Increase	7.96%	Increase	4.54%
Non-res	1,402,326,122		3.40%		1.93%

Appendix M



**SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES**

Terms and Conditions

The following Terms and Conditions and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (APS or Company). These Terms and Conditions are considered a part of all rate schedules, except where specifically excluded or changed by a written agreement. For a Customer whose service requirements are of unusual size or characteristics, additional or special contract arrangements may be required. If there is a conflict between any provision of a rate schedule and these Terms and Conditions, the provisions of the rate schedule apply.

1. Application for Service

Before supplying service APS will verify the identity of Applicant. Applicants may be required to appear at Company's place of business to produce proof of identity, sign an application, or execute a contract for service before APS supplies service. If there is no signed application or contract for service, APS's standard contract terms apply and the supplying of Standard Offer or Direct Access services and Customer's acceptance of service forms a service agreement between APS and the Customer for delivery, acceptance, and payment for services.

1.1 Grounds for Refusal of Service - APS may refuse service if any of the following conditions exist:

- (A) The Applicant has an outstanding amount due with APS for the same class of service and is unwilling to make payment arrangements that are acceptable to Company.
- (B) A condition exists that in Company's judgment is unsafe or hazardous.
- (C) The Applicant has failed to meet APS's security-deposit requirements outlined in Section 3.
- (D) The Applicant is known to be in violation of a Company Tariff.
- (E) The Applicant fails to furnish the funds, service, equipment, rights-of-way or Easements required to serve the Applicant and that have been specified by APS as a condition for providing service.
- (F) The Applicant falsifies his or her identity for the purpose of obtaining service.
- (G) Service is already being provided at the address for which the Applicant is requesting service.
- (H) Service is requested by an Applicant, and a prior Customer, who will reside at, or benefit from service at the premises, owes APS a delinquent bill for the same class of service, from the same or a prior service address.
- (I) The Applicant has failed to obtain any required permit or inspection indicating that the Applicant's facilities comply with current local construction and safety codes.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

2. Service-Establishment Charges

A Service-Establishment Charge of \$8.00 for residential or \$33.00 non-residential plus applicable adjustments will be assessed each time APS is asked to establish or re-establish electric service, or to make a special read without a disconnect and calculate a bill for a partial month.

2.1 Multiple Connects - If multiple connects are performed during the same site visit, in the same Applicant name, at the same address, and for the same class of service, APS will assess the Service-Establishment Charge once for every two Delivery Points.

2.2 After-hours Charge -The Customer must also pay an after-hours charge plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established after 5:00 p.m. on a day other than the day of request. The after-hours charge will be \$8.00 for residential with standard metering, \$137.00 plus applicable adjustments for residential with non-standard metering or \$164.00 plus applicable adjustments for non-residential.

2.3 Same-Day Connect Charge - The Customer must also pay a same-day connect charge of \$87.00 plus applicable adjustments if the Customer requests service, as defined in A.A.C. R14-2-203.D.3, be established or re-established on the same business day the request is being made, and APS agrees to work the request on the same day of the request. This will be charged regardless of the time the order may be worked by APS on that day. APS may, where no additional costs are incurred by Company, waive the same-day fee.

2.4 Non-Standard Service Request Charge -The Customer must also pay \$164.00 plus applicable adjustments per crew-person per hour when Customer requests services that do not meet the definition of Service-Establishment as defined in A.A.C. R14-2-203.D.3 and that require the availability of Company representatives after-hours, on a weekend day, or on a Company holiday. Examples of non-standard service requests are Customer-requested outages for maintenance and metering-equipment installations that include instrument transformers. The number of representatives used by APS to fulfill a request is in the Company's sole discretion. Customers will be given notice of estimated charges before the work is performed.

2.5 Waiving of Service Establishment Charge - Company may waive the Service-Establishment Charge if:

(A) The establishment of service is effective with the last Meter read date billed and a field trip is not required because Applicant accepts responsibility for energy billed and not yet paid.

(B) Applicant has an active Landlord Automatic Transfer of Service Agreement on file with Company.



**SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES**

3. Establishing Credit, Security Deposits and other forms of Credit Assurance

When credit cannot be established as provided for in Section 3.1 and 3.2 or when it is determined that the Applicant left an unpaid final bill owed to another utility company, the Applicant will be required to place a security deposit to secure payment of bills for service.

3.1 Residential Establishment of Credit - APS will not require a security deposit from a new Applicant for service at a primary or secondary residence if the Applicant can meet any of the following requirements:

- (A) The Applicant has had service of a comparable nature with APS within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months or been disconnected for nonpayment.
- (B) Company receives an acceptable credit rating, as determined by Company, for the Applicant from a credit-rating agency used by Company.
- (C) The Applicant can produce a letter regarding verification of credit from an electric utility where service of a comparable nature was last received within six months of the current date, and the utility states that the Applicant had a timely payment history for the prior 12 consecutive months.
- (D) If in lieu of a security deposit, Company receives an acceptable deposit-guarantee notification from a social or governmental agency or a surety bond in a sum equal to the required deposit.

3.2 Nonresidential Establishment of Credit - All nonresidential Applicants will be required to place a cash deposit to secure payment of bills for service, unless:

- (A) The Applicant had service of a comparable nature with Company within the past two years and was not delinquent in payment more than twice during the last 12 consecutive months and was not disconnected for nonpayment.
- (B) The Applicant provides a noncash security deposit in the form of a surety bond, irrevocable letter of credit, or assignment of monies in an amount equal to the required security deposit.

3.3 General Deposits Guidelines - If a security deposit is required, a separate deposit may be required for each service location.

- (A) Customer's security deposits will not preclude Company from terminating an agreement for service or suspending service if Customer fails to meet service-agreement obligations.
- (B) Company may choose to accept less than the full deposit required at time of service establishment based on Customer's financial condition.
- (C) A security deposit may increase or decrease if the Customer's average consumption increases or decreases by more than 10% for residential accounts



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

or 5% for nonresidential accounts within 12 consecutive months and credit has not been established.

(D) Where three or more additional residential services are requested, Company may require Customer to establish or reestablish a security deposit.

3.4 Residential Security Deposits - Residential security deposits will not exceed two times the Customer's average monthly bill as estimated by Company. APS may require a residential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within a 12 consecutive month period or has been disconnected for non-payment during the last 12 months.

3.5 Nonresidential Security Deposits - Nonresidential security deposits will not exceed two and one-half times the Customer's maximum monthly billing as estimated by Company. APS may require a nonresidential Customer to establish or reestablish a security deposit if the Customer becomes delinquent in the payment of two or more bills within 12 consecutive months or if the Customer has been disconnected for nonpayment during the last 12 months, or when the Customer's financial condition may jeopardize the payment of the bill, as determined by Company based on the results of using a credit-scoring worksheet. Company will inform all Customers of the Arizona Corporation Commission's complaint process should the Customer dispute the deposit based on the financial data.

3.6 Deposit Interest - Cash deposits held by APS six months (183 days or longer) earn interest from the date the deposit was collected at the established one-year Treasury Constant Maturities rate, effective on the first business day of each year, as published on the Federal Reserve Website.

3.7 Deposit Refunds - If the Customer terminates all service with Company, their security deposit may be credited to any remaining final bills. Any remaining credit balance will be refunded to the Customer of record within 30 days.

3.8 Residential security deposits or other instruments of credit will automatically expire or be credited or returned to the Customer's account after 12 consecutive months of service, if the Customer has not been delinquent in payments more than twice and the Customer has not filed bankruptcy in the last 12 months.

(A) **Nonresidential security deposits** and noncash deposits on file with Company will be reviewed after 24 months of service and will be returned if:

- (1) The Customer has not been delinquent in payments more than twice, has not been disconnected for non-payment, and has not filed for bankruptcy during the previous 12 consecutive months; and
- (2) Customer's financial condition does not warrant an extension of the security deposit.



**SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES**

4. Rates

The Customer's service characteristics and service requirements determine the selection of the applicable rate schedule.

4.1 Rate Selection - APS will use reasonable care in initially establishing service to the Customer under the most advantageous rate schedule applicable to the Customer. Because of varying Customer usage patterns and other reasons beyond APS's reasonable knowledge or control, Company cannot guarantee that the most economic applicable rate will be applied. APS will not make any refunds in any instance where it is determined that the Customer would have paid less for service had the Customer been billed on an alternate rate or provision of that rate.

4.2 Rate Information - APS will provide, in accordance with A.A.C. R14-2-204, a copy of any rate schedule applicable to the Customer for the requested type of service. In addition, APS will notify its Customers of any changes in Company Tariff affecting those Customers.

4.3 Optional Rates - Optional rate schedules are available for certain classes of service. After establishing service a Customer may choose an alternate rate schedule effective from the next regularly scheduled Meter reading, after the appropriate metering equipment is reprogrammed or installed. No further rate schedule changes may be made within the succeeding 12 month period. If the rate schedule or contract under which the Customer is provided service specifies a term, the Customer may not exercise its option to select an alternate rate schedule until expiration of that term.

5. Billing

Billing Periods for service normally consist of approximately 30 days unless otherwise designated under rate schedules, through contractual agreement, or at Company option.

5.1 Payment of Bills - The Customer is responsible for paying bills until service is ordered discontinued and Company has had reasonable time to secure a final Meter reading for those services involving energy usage, or, if nonmetered services are involved, until Company has had reasonable time to process the disconnect request.

5.2 Failure to Receive Bills or Notices (including notices of disconnection) which have been properly placed in the United States mail or sent through alternative billing forms, such as electronic mail, will not prevent such bills from becoming delinquent or prevent the notices from being effective, or relieve the customer of their obligations.

5.3 Incentive for Electronic Payments - A monthly incentive of \$0.48 per Customer will be given to Customers who elect to pay their bills using the Company's electronically transmitted payment options AutoPay, SurePay or similar programs.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 5.4 Billing Errors** - When an error is found in the billing sent to the Customer, APS will correct the error to recover or refund the difference between the original billing and the correct billing. Adjusted billings will not be sent for periods beyond the applicable statute of limitations from the date the error is discovered.
- 5.5 Corrected Charges for Overbilling** - Refunds or credits to Customers resulting from overbillings will be made promptly upon discovery by Company.
- 5.6 Corrected Charges for Underbilling** - Except as specified below, corrected charges for underbillings will be limited to three months for residential accounts and six months for nonresidential accounts. Customers will be given an equal length of time, such as the number of months underbilled, to pay the backbill without late-payment penalties. Where the account is billed on a special contract or nonmetered rate, corrected charges for underbillings will be billed in accordance with the contract or rate-schedule requirements and is not limited to three or six months as applicable.
- (A) Where service has been established but no bills have been rendered, corrected charges for underbillings will go back to the date service was established.
 - (B) Where there is evidence of Meter Tampering or energy diversions, corrected charges for underbillings will go back to the date Meter Tampering or energy diversions began, as determined by Company, and APS is not required to give an equal length of time, such as the number of months underbilled, to pay the backbill. APS will work with Customer to establish a payment plan that is acceptable to Company.
 - (C) Where lack of access to the Meter (caused by the Customer) has resulted in estimated bills, corrected charges for underbillings will go back to the Billing Month of the last Company-obtained Meter-read date.
 - (D) Where actual Customer usage can be determined without estimating reads, corrected charges for underbillings are not limited to three or six months, as applicable. In no event may such rebilling exceed the applicable statute of limitations.
- 5.7** Company may forgo correcting a billing error if the amount over or under billed is de minimis and the cost of rebilling does not justify the cost and time required to rebill.
- 6. Collection Policy**
The following collection policies apply to all Customer accounts:
- 6.1 Delinquent Bills** - All bills rendered by Company are due and payable no later than 15 calendar days from the billing date. Any payment not received within this time frame are delinquent. All delinquent accounts, for which payment has not been received, are subject to the provisions of Company's termination procedure.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

Company may suspend or terminate a Customer's service for nonpayment of any Arizona Corporation Commission approved charges.

6.2 Late Charges - All delinquent charges, including past due security deposits, are subject to a late charge at the rate of 18% per annum (1.5% per month) plus applicable adjustments.

6.3 Transfer of Outstanding Bills - If a Customer has two or more services with APS and one or more services are terminated for any reason leaving an outstanding bill, and the Customer is unwilling to make payment arrangements that are acceptable to Company, Company may transfer the balance due on the terminated service to any other active account of the Customer for the same class of service. The Customer's failure to pay the active account will result in the suspension or termination of service. If service is requested by two or more individuals, Company has the right to collect the full amount owed from any one of the Customers.

6.4 Dishonored Payments - If Company is notified by the Customer's financial institution that it will not honor a payment tendered by the Customer for payment of any bill, Company may require the Customer to make payment in cash, or by money order, certified or cashier's check, or other means that guarantee the Customer's payment to Company.

(A) The Customer will be charged a fee of \$15.00 plus applicable adjustments for each instance where the Customer's payment is not honored by the Customer's financial institution.

(B) The tender of a dishonored payment in no way relieves the Customer of the obligation to pay Company under the original terms of the bill, or defers the Company's right to terminate service for nonpayment of bills.

(C) Where the Customer has tendered two or more dishonored payments in the past 12 consecutive months, Company may require the Customer to make payment in cash, or money order or cashier's check for the next 12 consecutive months.

6.5 Collection Agency Referrals - All unpaid delinquent final bills may be referred to a collection agency for collection. If collection-agency referral is warranted, Customer may be responsible for the associated collection-agency fees incurred.

7. Termination of Service

7.1 To avoid termination of service, the Customer will make payment in full, including any necessary deposit as outlined in Section 3, or make payment arrangements that are satisfactory to Company.

7.2 If service is terminated, APS will not restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

APS may also require payment of Same-Day and After-Hours charges prior to restoring service

7.3 Termination of Service With Notice - APS may, without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, if Company has met the notice requirements established by the Arizona Corporation Commission:

- (A) Customer's violation of any applicable rules of the Arizona Corporation Commission or Company Tariff.
- (B) A Customer's failure to pay a Delinquent Bill for services provided by Company.
- (C) The Customer's breach of a written contract for service.
- (D) The Customer's failure to comply with Company's deposit requirements.
- (E) The Customer's failure to provide Company with satisfactory and unassisted access to Company's equipment.
- (F) When necessary to comply with an order of any governmental agency having jurisdiction.
- (G) A prior Customer's failure to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the premises.
- (H) Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.
- (I) Company learns of the existence of any condition in Section 1.1 - Grounds For Refusal of Service.

7.4 Termination of Service Without Notice - Company may, without liability for injury or damage, disconnect service to any Customer without advance notice under any of the following conditions:

- (A) If Company observes, or has evidence of, a hazard to the health or safety of persons or property;
- (B) If Company has evidence of Meter Tampering or fraud.
- (C) If Company has evidence of unauthorized resale or use of electric service.
- (D) The Customer fails to comply with the curtailment procedures imposed by Company during a supply shortage.

7.5 Termination of Service for Dishonored Payment - Before reconnecting service, payment of funds resulting from a dishonored payment and all other delinquent amounts will be required in cash, money order, or certified funds. If Customer has already received a notice of disconnection at the time the bill became past due, APS may, without liability for injury or damage, disconnect service without additional notice under any of the following conditions:

- (A) When Customer makes payments to avoid or stop disconnection with a dishonored payment and has already received a notice at the time the bill became past due.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

(B) When Customer pays to reconnect service with a dishonored payment and has already received a notice at the time the bill became past due.

7.6 Termination Process Charges - Company will require payment of a Field Call Charge of \$10.00 plus applicable adjustments when an authorized Company representative travels to the Customer's site to accept payment on a delinquent account, notify of service termination, make payment arrangements, or terminate the service. This charge only applies for field calls resulting from the termination process.

(A) If a termination is required at the pole the reconnection charge will be \$89.00 plus applicable adjustments.

(B) If a termination is in underground equipment the reconnection charge will be \$135.00 plus applicable adjustments.

8. Metering & Metering Equipment

8.1 Standard Metering - The Company's standard method of measuring energy usage is through the use of Automated Metering Infrastructure (AMI) metering equipment. All customers will be served using the Company's standard metering equipment unless:

(A) the customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used; or

(B) the customer meets all eligibility requirements for non-standard metering and voluntarily requests non-standard metering.

8.2 Non-Standard Metering - The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and must be read manually each month. Certain optional rates may not be available to customers who select a non-standard meter.

8.3 Non-Standard Metering Eligibility - Only residential customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or customers with newly installed rooftop solar, are not eligible for non-standard metering.

8.4 Non-Standard Metering Charges - The following charges will apply when a customer voluntarily requests, and is granted, non-standard metering as described in Section 8.1(B):

(A) Monthly Meter Reading Charge: \$5.00

(B) Non-Standard Metering Set-up Fee: A \$50.00 one-time charge for customers with existing AMI meter.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- (C) Customers in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used [see 8.1(A)] will not be billed a non-standard meter reading charge.
- 8.5 Discontinuation of Non-Standard Metering** - The Company may replace a non-standard meter with a standard meter, without notifying the customer prior to replacement, under any of the following conditions:
- (A) Company employees observe or have evidence of a safety hazard to employees, customers, or Company or customer property.
 - (B) Company employees observe or have evidence of meter tampering, energy diversion, or fraud.
 - (C) Company has evidence of unauthorized resale of electricity.
 - (D) Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to Company equipment, and physical threats such as weapons or dogs.
 - (E) All terms and conditions in Section 7, regarding termination of service, will also apply.
- 8.6 Measuring Customer Service** - All energy sold to the Customer by Company will be measured by commercially acceptable measuring devices. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company. The readings of the Meter will be conclusive as to the amount of electric power supplied to the Customer unless there is evidence of Meter Tampering or energy diversion or unless a test reveals the Meter is in error by more than 3%, either fast or slow.
- 8.7 Meter Rereads** - When requested by Customer, APS will reread the customer's Meter within 10 working days after the request. The cost of each reread is \$14.00 plus applicable adjustments if the original reading was not in error.
- 8.8 Meter Testing** - APS tests its Meters regularly in accordance with a Meter testing and maintenance program approved by the Arizona Corporation Commission. APS will individually test a Company owned and maintained Meter upon Customer request.
- If after testing, a Meter is found to be more than 3% in error, either fast or slow, correction will be made of previous readings and adjusted bills will be rendered.
- 8.9 Meter Test Charge** - If the Meter is found to be within the plus or minus 3% limit, Company may charge the Customer \$44.00 plus applicable adjustments for Meter test if the Meter is removed from the site and tested in the meter shop, or \$93.00 plus applicable adjustments if the Meter remains on site and is tested in the field.
- 8.10 Meter Tampering** - If there is evidence of Meter Tampering or energy diversion, the Customer, person, or entity demonstrated to have tampered with the Meter, or benefited from the tampering or diversion will be billed for the estimated



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

energy and, if applicable, Demand, for the period in which the energy diversion took place. Additionally, where there is evidence of Meter Tampering, energy diversion, or by-passing the Meter, the Customer, person or entity demonstrated to have tampered with the Meter or diverted energy will also be charged the cost of the investigation as determined by Company.

- 9. Service Installations & Metering** - The Customer's service installation will normally be arranged to accept only one type of service at one Point of Delivery to enable service measurement through one Meter. If the Customer requires more than one type of service, or total service cannot be measured through one Meter according to Company's regular practice, separate Meters will be used and separate billing rendered for the service measured by each Meter.

9.1 Customer Equipment - The Customer must install and maintain all wiring and equipment beyond the Point of Delivery except for Company's Meters and special equipment. The Customer's entire installation must conform to all applicable construction standards and safety codes, and the Customer must furnish an inspection or permit if required by law or by Company. In circumstances where a clearance is not required by law, Company may require Customer to execute a Letter In-Lieu of Electrical Clearance. The Customer must also provide, in accordance with APS's current service standards and Electric Service Requirements Manual, at no expense to Company, and close to the Point of Delivery, a space that is, in the Company's opinion, both suitable and sufficient for installing, accessing and maintaining Company's metering equipment. A current version of the Electric Service Requirements Manual is available on-line on the Company's website.

9.2 Special Meter-Reading Device - Where a Customer requests, and Company approves, a special Meter-reading device or communications services or devices to accommodate the Customer's needs, the cost for the additional equipment and usage fees are the Customer's responsibility.

9.3 Totalized Metering and Billing - Company normally meters and bills each site separately. But, at Customer's request, adjacent and contiguous sites (not separated by private or public property or right of way), operated as one integral unit under the same name and as a part of the same business, may at Company's option, be considered a single site as specified in Company's Schedule 4, Totalized Metering of Multiple Service Entrance Sections at a Single Site for Standard Offer and Direct Access Service.

9.4 Service Connections - Company is not required to install or maintain any lines and equipment on the Customer's side of the Point of Delivery except its Meter.

(A) For overhead service, the Point of Delivery is where Company's service conductors terminate at the Customer's weatherhead or bus rider.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- (B) For underground service, the Point of Delivery is where Company's service conductors terminate in the Customer's or development's service equipment. The Customer must furnish, install, and maintain any risers, raceways, or termination cabinet necessary for installing Company's underground service conductors.
- (C) For special Applications where service is provided at voltages higher than the standard voltages specified in the Electric Service Requirements Manual, the designated Point of Delivery must be mutually agreed on by the parties.
- (D) For the mutual protection of the Customer and Company, only authorized employees or agents of Company or the Load Serving ESP are permitted to make and energize the connection between Company's service wires and the Customer's service entrance conductors. APS employees must carry Company-issued identification that they will show on request.

10. Customer Obligations

10.1 Load Characteristics - The Customer must exercise reasonable care to ensure that the electrical characteristics of its load, such as deviation from sine-wave form (a minimum standard is IEEE 519) or unusual short interval fluctuations in Demand, do not impair service to other Customers or interfere with operating any telephone, television, or other communication facilities. Customer must meet power factor requirements as specified in the applicable rate schedules.

10.2 Easements - All suitable Easements or rights-of-way required by Company for any portion of an extension to serve a Customer, which is either on sites owned, leased, or otherwise controlled by the Customer or developer, or other property required for the extension, will be furnished in Company's name by the Customer without cost to or condemnation by Company and in reasonable time to meet proposed service requirements. All Easements or rights-of-way granted to, or obtained on behalf of Company will contain terms and conditions that are acceptable to Company. When Company discovers that the Customer or the Customer's agent is performing work, has constructed facilities, or has allowed vegetation to grow, adjacent to or within an Easement or right-of-way or Company-owned equipment, and the work, construction, vegetation, or facility poses a hazard, or violates federal, state, or local laws, ordinances, statutes, rules, or regulations, or significantly interferes with Company's safe use, operation, or maintenance of, or access to, equipment, or facilities, Company will notify the Customer or the Customer's agent and take whatever actions are necessary to eliminate the hazard, obstruction, interference, or violation at the Customer's expense. Company will notify the Customer in writing of the violations.

10.3 Access for Repair, Maintenance and Service Restoration - Company's authorized agents must have satisfactory unassisted 24 hour a day, seven days a week access



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

to Company's equipment located on Customer's sites for the purpose of repair, maintenance, and service-restoration work that Company may need to perform.

10.4 Access for Install, Inspect, Read, or Remove - Company's authorized agents must have satisfactory unassisted access to the Customer's sites at all reasonable hours to install, inspect, read, or remove its Meters or to install, operate, or maintain other Company property, to verify that Customer is in compliance with its obligations, or to inspect and determine the connected electrical load.

10.5 Trip Charge - A trip charge of \$22.00 for residential or \$26.00 for non-residential, plus applicable adjustments will be assessed each time an authorized Company representative travels to a site and is unable to complete a Customer's service request because of lack of access to the Point of Delivery.

10.6 Six Months No Access - If Company, in its opinion, does not have satisfactory unassisted access to the Meter after six months (not necessarily consecutive) of good-faith efforts to work with the Customer, then Company has sufficient cause to terminate service or deny any rate options where, in Company's opinion, access is required.

10.7 Remedies - The remedy for unassisted access will be at APS's discretion and may include the installation by Company of a specialized Meter. If a specialized Meter is installed, the Customer will be billed the difference between the otherwise applicable Meter for Customer's rate and the specialized Meter plus the cost incurred to install the specialized Meter as a one-time charge and any reoccurring incremental costs. If service is terminated as a result of failure to provide unassisted access, APS verification of unassisted access will be required before service is restored. Written termination notice is required before disconnecting service under this section.

11. Company Obligations

11.1 Customer-Specific Information - Customer-specific information will not be released without Customer's specific prior written authorization unless the information is requested by a law-enforcement or other public agency, or is requested by the Arizona Corporation Commission or its staff, or is reasonably required for legitimate account-collection activities, or is necessary to provide efficient, effective, safe, or reliable service to the Customer. Customer-specific information may be provided to suppliers of goods or services under contract with Company if the goods or services will help Company to provide efficient, effective, safe, or reliable service; and the contract includes a requirement that the information be kept confidential and be used only to fulfill the supplier's obligations to Company.

11.2 Service Voltage - Company will deliver electric service to the designated Point of Delivery, as specified in Section 9.4 of this Schedule, at the standard voltages



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

specified in the Company's Electric Service Requirements Manual and as specified in A.A.C. R14-2-208.F. Company may deliver service for special applications at higher voltages, with prior approval from Company's Engineering Department and in accordance with Company's Schedule 3, Conditions Governing Extensions of Electric Distribution Lines and Services approved by the Arizona Corporation Commission.

12. Limitations on Liability of Company

12.1 Service Interruptions - Company is not liable to the Customer for any damages caused by Load Serving Electric Service Provider's equipment or failure to perform, fluctuations, interruptions, or curtailment of electric service, except where caused by Company's willful misconduct or gross negligence.

- (A) Company may, without incurring any liability, suspend the Customer's electric service for periods reasonably required to permit Company to accomplish repairs to, or changes in, any Company's facilities.
- (B) The Customer is responsible for protecting Customer's own sensitive equipment from harm caused by variations or interruptions in power supply.
- (C) If a national emergency or local disaster results in disruption of normal service, Company may, in the public interest and on behalf of Electric Service Providers or Company, interrupt service to other Customers to provide necessary service to civil-defense or other emergency-service agencies on a temporary basis until normal service to these agencies can be restored.

12.2 Use of Service or Apparatus - The Customer will save Company harmless from and against all claims for injury or damage to persons or property occasioned by or in any way resulting from the services being provided by Company or their use on the Customer's side of the Point of Delivery. Company has the right to suspend or terminate service if Company learns of service use by the Customer under hazardous conditions.

- (A) The Customer will exercise all reasonable care to prevent loss or damage to Company property installed on the Customer's site for the purpose of supplying service to the Customer. The Customer is responsible for payment for loss or damage to Company property on the Customer's site arising from neglect, carelessness, or misuse, and will reimburse Company for the cost of necessary repairs or replacements.
- (B) The Customer is responsible for payment of any equipment damage or estimated unmetered usage resulting from unauthorized breaking of seals, interfering with, tampering with, or by-passing the Meter.
- (C) The Customer is responsible for notifying APS of any failure in Company's equipment.



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

- 12.3 Removal of Facilities** - Upon termination of service, Company may, without liability for injury or damage, dismantle and remove its facilities, installed for the purpose of supplying service to the Customer, and Company will have no further obligation to serve the Customer.
- 13. Successors and Assigns** - Agreements for Service are binding on and for the benefit of the successors and assigns of the Customer and Company, but no assignments by the Customer are effective until the Customer's assignee agrees in writing to be bound and until the assignment is accepted in writing by Company.
- 14. Warranty** - There are no understanding, agreements, representations, or warranties, expressed or implied (including warranties regarding merchantability or fitness for a particular purpose), not specified here or in the applicable rules of the Arizona Corporation Commission concerning the sale and delivery of services by Company to the Customer. These Terms and Conditions and the applicable rules of the Arizona Corporation Commission state the entire obligation of Company in connection with sales and deliveries.
- 15. Direct Access Service** - *NOTE: Retail Electric Competition is currently on hold in APS Service Territory.*
- 15.1 Direct Access Service Request (DASR)** - A Direct Access Service Request charge of \$10.00 plus any applicable adjustments will be assessed to the Electric Service Provider (ESP) submitting the DASR each time Company processes a Request (RQ) type DASR as specified in Company's Schedule 10, Terms and Conditions for Direct Access.
- 15.2 Direct Access Service** - Direct Access Service will be effective upon the next Meter read date if DASR is processed 15 calendar days before that read date and the appropriate metering equipment is in place. If a DASR is made less than 15 calendar days before the next regular read date, the effective date will be at the next Meter read date. The above timeframes are applicable for Customers changing their selection of ESP or for Customers returning to Standard Offer service.
- (A)** Any Customer that selects Direct Access service may return to Standard Offer service in accordance with the rules, regulations, and orders of the Arizona Corporation Commission. The Customer will not be eligible for Direct Access service for the succeeding 12 months.
- (B)** If a Customer returning to Standard Offer, in accordance with the rules, regulations and orders of the Commission, was not given the required notification in accordance with the rules and regulations of the Commission by their Load Serving ESP of its intent to cease providing competitive services



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

then the above provision will apply only if the Customer fails to select another ESP within 60 days of returning to Standard Offer service.

- (C) Unpaid charges incurred before the Customer selects Direct Access will not delay the Customer's request for Direct Access. These charges remain the responsibility of the Customer to pay. Normal collection activity, including discontinuing service, may result from failure to pay.
- (D) Where the ESP is the MSP or MRSP, and the ESP or its agent fails to provide the Meter data to Company under Company's Schedule 10 Section 8.16, Meter Reading Data Obligations, Company may, at its option, obtain the data or estimate the billing determinants.
- (E) Where Company is the MRSP, Company will, at the request of the Customer or the ESP, reread or test the Customer's Meter within 10 working days after the request. The cost of each reread or test may be applied to the Customer or ESP when applicable.
- (F) All energy sold to the Customer by MRSP will be measured by commercially acceptable measuring devices and under the terms and conditions of Company's Schedule 10 - Terms and Conditions for Direct Access.

15.3 Direct Access Deposits - If the Customer chooses to change from Standard Offer to Direct Access services, the deposit may be decreased by an amount that reflects the portion of the Customer's service being provided by a Load Serving ESP. If the Load Serving ESP is providing ESP Consolidated Billing under Company's Schedule 10 Section 7, the entire deposit will be credited to the Customer's account; or, if the Customer chooses to change from Direct Access to Standard Offer service, the requested deposit amount may be increased by an amount under Section 3.3 which reflects that Company is providing bundled electric service.

15.4 Direct Access and Company Equipment

- (A) **Meters** - A Meter Service Provider (MSP) or its authorized agents may remove Company's metering equipment under Company's Schedule 10 Terms and Conditions for Direct Access. Meters not returned to Company or returned damaged will result in charge to the MSP of the replacement costs, plus an administration fee of 15%, less five year's depreciation.
- (B) **Lock-rings** - Company will lease lock-ring keys to MSP's or their agents who are authorized to remove Company Meters under the terms and conditions of Company's Schedule 10 at a refundable charge of \$70.00 plus applicable adjustments per key. The charge will not be refunded if a key is lost, stolen, or damaged. If Company must replace 10% of the issued keys within any 12 month period because of loss by the MSP's agent, Company may, rather than leasing additional lock ring keys, require the MSP to arrange for a joint



**SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES**

meeting. All lock-ring keys must be returned to Company within five working days if the MSP or its authorized agents are:

No longer permitted to remove Company Meters under the conditions of Company's Schedule 10;

(1) No longer authorized by the Arizona Corporation Commission to provide services; or

(2) The ESP Agreement has been terminated.

(C) **Site Meetings** - If the MSP, the Customer, or the Customer's agent requests a joint site meeting for removal of Company metering and associated equipment or lock ring, a base charge of \$62.00 plus applicable adjustments per site will be assessed. Company may assess an additional charge of \$53.00 plus applicable adjustments per hour for joint site meetings that exceed 30 minutes. If Company must temporarily replace the MSP's Meter or associated metering equipment during emergency situations or to restore power to a Customer, the above charges may apply.

DEFINITIONS

Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]

Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]

Billing Month means the period between any two regular readings of the utility's Meters at approximately 30 day intervals. [A.A.C. R14-2-201-(5)]

Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]

Company holidays (as referred to in section 2.4) are New Year's Day, Martin Luther King Jr. Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, the day after Thanksgiving, and Christmas Day.

Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

Delinquent Bill means a bill in which current electric charges are considered past due (15 calendar days after the statement date).

Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(12)]

Distribution Lines means the utility lines operated at distribution voltages which are constructed along public roadways or other bona fide rights-of-way, including Easements on Customer's property. [A.A.C. R-14-2-201-(13)]

Easement means a property owner ("Grantor") grants the right to use the owner's land to another party. An easement gives Company the right to have Company lines on property not owned by the Company. This allows Company to build, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity. The Grantor may continue to use the land along the easement within certain limitations.

Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer ("Landlord") and Company, that provides continuous and uninterrupted service to the Landlord during intervals when a Landlord has no tenants. A Service Establishment Charge will not apply and service will automatically be transferred into the Landlord's name. Landlord Automatic Transfer of Service Agreements are available to property owners that have established credit with Company.

Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(23)]

Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(25)]

Meter tampering means a situation where a meter has been altered or bypassed without prior written authorization from Company. Common examples are meter bypassing, use of magnets to slow the meter recording, and broken meter seals. [A.A.C. R14-2-201(26)]

Minimum charge means the amount the customer must pay for the availability of electric service, including an amount of usage, as specified in the utility's tariffs. [A.A.C. R14-2-201(27)]



SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

Point of delivery or delivery point means the point where facilities owned, leased, or under license by a customer connects to the utility's facilities. [A.A.C. R14-2-201(31)]

Tariffs mean the documents filed with the Arizona Corporation Commission which list the services and products offered by the utility and which set forth the terms and conditions and a schedule of the rates and charges, for those services and products. [A.A.C. R14-2-201(42)]

Statement of Charges		
Description	Charge	Reference
Residential Service Establishment Charge	\$8.00	2
Nonresidential Service Establishment Charge	\$33.00	2
After hours Charge –Residential Standard Metering	\$8.00	2.2
After hours Charge –Residential Non-Standard Metering	\$137.00	2.2
After hours Charge –Nonresidential	\$164.00	2.2
Same Day Connect Charge	\$87.00	2.3
Non-Standard Service Request Charge (per crew person, per hour)	\$164.00	2.4
Electronically Transmitted Payment Discount	-\$0.48	5.3
Dishonored Payment Fee	\$15.00	6.4
Field Call Charge	\$10.00	7.6
Overhead Reconnection Charge	\$89.00	7.6
Underground Reconnection Charge	\$135.00	7.6
Non-Standard Metering- Monthly Meter Reading	\$5.00	8.4
Non-Standard Metering Set-up fee for customer with existing AMI meter	\$50.00	8.4
Meter Reread	\$14.00	8.7
Meter test in shop	\$44.00	8.9
Meter test at site	\$93.00	8.9

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Charles A. Miessner
Title: Manager, Regulation and Pricing
Original Effective Date: December 1951

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Effective: xxxx xx, xxxx



**SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES**

Trip Charge - Residential	\$22.00	10.5
Trip Charge - Nonresidential	\$26.00	10.5

Appendix N



Appendix N
Page 1 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

General Description

This schedule establishes the Terms and Conditions under which Company will extend, relocate, and upgrade its facilities in order to provide service. Provision of electric service from Arizona Public Service Company (APS or Company) may require construction of new facilities or the relocation or upgrade of existing facilities. Costs for construction depend on the applicant's location, scope of project, load size, and load characteristics. Costs include, but are not limited to, project management, coordination, engineering, design, surveys, permits, construction inspection, and support services.

All facility installations and upgrades will be made in accordance with good utility construction practices, as determined by Company, and are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension as determined by Company.

The following provisions govern the installation of overhead and underground electric distribution facilities to applicants whose requirements are deemed by Company to be usual and reasonable in nature.

1. Definitions

- 1.1 **APS Approved Electrical Distribution Contractor** means an electrical contractor who is licensed in the State of Arizona and properly qualified to install electric distribution facilities in accordance with Company standards and good utility construction practices as determined by Company.
- 1.2 **Backbone Infrastructure** means the electrical distribution facilities typically consisting of main three-phase feeder lines and/or cables, conduit, duct banks, manholes, switching cabinets and capacitor banks.
- 1.3 **Conduit Only Design** means the conduit layout design for the installation of underground Extension Facilities that will be required when the Extension Facilities are to be installed at a later date.
- 1.4 **Conversion** means converting overhead distribution facilities to underground facilities.
- 1.5 **Corporate Business and Industrial Park Development** means a tract of land which has been divided into contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of buildings for commercial or industrial use.
- 1.6 **Doubtful Permanency** means a customer who in the opinion of the Company is neither Permanent nor Temporary. Service which, in the opinion of the Company, is for operations of a speculative character is considered Doubtfully Permanent.
- 1.7 **Economic Feasibility** means a determination by Company that the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) less the cost of service provides an adequate rate of return on the investment made by Company to serve the applicant.
- 1.8 **Execution Date** means the date Company signs the agreement after the applicant has



SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

signed the agreement and money has been collected by company.

- 1.9 **Extension Facilities** means the electrical facilities, including conductors, cables, transformers, and related equipment installed solely to serve an individual applicant, or groups of applicants. For example, the Extension Facilities to serve a Residential Subdivision would consist of the line extension required to connect the subdivision to Company's existing system, as well as Company's electrical facilities constructed within the subdivision which would include primary and service lines, and transformers.
- 1.10 **High Rise Development** means a building built with four or more floors (usually using elevators for accessing floors) that may consist of residential or non-residential use, or a combination of both residential and non-residential uses.
- 1.11 **Irrigation** means water pumping service.
- 1.12 **Line Extension Agreement** means the contractual agreement between Company and applicant that defines applicant payment requirements, terms of refund, scope of project, estimated costs, and construction responsibilities for Company and the applicant. Line Extension Agreements may be assigned to applicants successors in interest with Company approval, which approval will not be unreasonably withheld.
- 1.13 **Master Planned Community Development** means a development that consists of a number of separately subdivided parcels for different Residential Subdivisions. The development may also incorporate a variety of uses including multi-family, non-residential, and public use facilities.
- 1.14 **Master Meter** means a meter for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage.
- 1.15 **Metro Area** means a city with a population of 750,000 or more and its contiguous and surrounding communities.
- 1.16 **Mixed-Use Development** means a development that consists of both residential and non-residential uses, such as a building with three stories or less, where the first level is for commercial purposes and the upper floors are for residential units, or a development that includes an apartment complex and a commercial center, or a development that includes a subdivision and a water treatment plant.
- 1.17 **Permanent** means a customer who is a tenant or owner of a service location who applies for and receives electric service, which, in the opinion of the Company, is of a permanent and established character. The use of electricity may be continuous, intermittent, or seasonal in nature. Permanency at the service location may be established by such things as city/county/state permits, a permanent water system, an approved sewer/septic system, or other permanent structures.
- 1.18 **Project-Specific Cost Estimate** means cost estimates that are developed recognizing the unique characteristics of large or special projects to which the Schedule of Charges is not applicable. A Project-Specific Cost Estimate provided to an applicant is valid for a period of up to six months from the date the estimate is provided to the applicant.
- 1.19 **Relocation** means moving a distribution line or facilities from its current location to a new location.



SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

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- 1.20 **Residential "Lot Sale" Development** means a tract of land that has been divided into four or more contiguous lots in which a developer offers improved lots for sale and the purchaser of the lot is responsible for construction of a residential home and the costs to provide service, which may include backbone, transformer and service.
- 1.21 **Residential Multi-Family Development** means a development consisting of apartments, condominiums, or townhouses with less than four floors.
- 1.22 **Residential Single Family** means a house, or a manufactured or mobile home Permanently affixed to a lot or site.
- 1.23 **Residential Subdivision** means a tract of land, which has been divided into four or more contiguous lots with an average size of one acre or less, in which the developer is responsible for the costs to provide service, including backbone, transformers and services for the residential homes or permanent manufactured or mobile home sites.
- 1.24 **Residual Value** means the remaining un-depreciated original cost of the existing facilities to be removed
- 1.25 **Rural Arizona Municipality** means Arizona incorporated cities and towns with populations of less than 150,000 (based on U.S. Census Bureau 2010 population data) not contiguous with or situated within a Metro Area.
- 1.26 **Rural Municipal Business Development** means a tract of land which has been divided into contiguous lots, is owned and developed by an Rural Arizona Municipality, and where the Rural Arizona Municipality will be the lease-holder for future permanent applicants.
- 1.27 **Schedule of Charges** means the list of charges that is used to determine the applicant's cost responsibility for the Extension Facilities.
- 1.28 **Service Entrance Upgrade** means the replacement of the customer's electric panel to one with larger load capacity. This includes panels that are upgraded to a larger amperage rating, greater voltage or additional phases (1 phase to 3 phase).
- 1.29 **Temporary** means premises or enterprises which are temporary in character, or where it is known in advance that the Extension Facilities will be of limited duration.

2. General Provisions for Service

- 2.1 **Applicant Classification** - For the purposes of this Service Schedule 3, applications for Extension Facilities will be classified as "Residential" or "General Service" as listed below, and further described in the referenced sections.
- (A) Residential classifications are: "Residential Single Family Home" (Section 3), "Residential Subdivision Developments" (Section 4), "Residential "Lot Sale" Developments (Section 5), "Master Planned Community Developments" (Section 6) or "Residential Multi-Family Developments" (Section 7).
- (B) General Service classifications are: "Basic General Service" (Section 9), "High Rise Developments" (Section 10), Mixed-Use Developments (Section 11), "Corporate Business & Industrial Park Developments" (Section 12), "Temporary Applicants" (Section 13), and "Doubtful Permanency Customers" (Section 14).



Appendix N
Page 4 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

- 2.2 **Schedule of Charges** -An applicant requesting an extension will be provided a sketch showing the Extension Facilities and an itemized cost quote based on the Schedule of Charges or other applicable details. The Schedule of Charges is attached to this Service Schedule as Attachment 1. When the Schedule of Charges is not applicable, charges for Extension Facilities will be determined by the Company based on Project-Specific Cost Estimates. The Schedule of Charges is not applicable for the following:
- (A) Extension Facilities requiring modifications, removal, relocations or conversions of existing facilities in conjunction with a new extension or existing customer requested upgrade. The removal, replacement, conversion, and new Extension Facilities charges will be determined by a combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project and may include residual value costs as computed in accordance with the method described in A.R.S 40-347.
 - (B) Extension Facilities required for modifications, relocations or conversions of existing facilities not in conjunction with a new extension or existing customer upgrade.
 - (C) Extension Facilities for General Service applicants with estimated demand loads of three megawatts or greater, or that require in aggregate 3,000 kVA of transformer capacity or greater.
 - (D) Extension Facilities that require three-phase transformer installations greater than the sizes noted in the Schedule of Charges.
 - (E) Extension Facilities required for High Rise Developments, Mixed-Use Developments, Master Planned Developments or Temporary service.
 - (F) Extension Facilities involving spot networks, vault installations, primary metering, or specialized or additional equipment for enhanced reliability.
 - (G) Special studies, leases or permits required by the city, county, state or federal governmental agency for installing electric facilities on private, government or public lands.
- 2.3 **General Underground Construction Policy** - With respect to all underground installations under a Line Extension Agreement, Company will install underground facilities only if all of the following conditions are met:
- (A) The Extension Facilities meet all requirements as specified in "Residential" or "General Service" Sections 2.1 (A) & (B) of this Service Schedule 3.
 - (B) The applicant signs a trench agreement and provides all earth-work including, but not limited to, trenching, boring or punching, backfill, compaction, and surface restoration in accordance with Company specifications.
 - (C) The applicant provides installation of equipment pads, pull-boxes, manholes, conduits, and appurtenances as required and in accordance with Company specifications.
 - (D) In lieu of applicant providing these services and equipment, the applicant may pay Company to provide these services and equipment as a non-refundable contribution in aid of construction. The payment will equal the cost of such work plus any



SERVICE SCHEDULE 3

**CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES**

administrative or inspection fees incurred by Company. Applicants electing this option will be required to sign an agreement indemnifying and holding Company harmless against claims, liabilities, losses or damage (Claims) asserted by a person or entity other than Company's contractors, which Claims arise out of the trenching and conduit placement, provided the Claims are not attributable to the Company's gross negligence or intentional misconduct.

- 2.4 Refunds** - The following general refund conditions will apply:
- (A) No refund will be made to any applicant for an amount more than the unrefunded balance of the applicant's refundable advance.
 - (B) Company reserves the right to withhold refunds to any applicant who is delinquent on any account, agreement, or invoice, including the payment of electric service, and may apply these refund amounts to past due bills.
 - (C) The refund eligibility period for Basic General Service and High Rise Development will be five years from the date Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.
 - (D) The refund eligibility period for Residential Subdivisions and Multi-Family Developments will be five years and will start three months from the date Company executes the Line Extension Agreement with the applicant. Any unrefunded advance balance will become a non-refundable contribution in aid of construction five years from the Execution Date of the agreement.
 - (E) Refunds will be mailed to the applicant of record noted on the executed agreement no later than 60-days from the annual review date.
- 2.5 Interest** - All refundable advances made by the applicant to the Company will be non-interest bearing.
- 2.6 Ownership** - Except for applicant owned facilities, all Extension Facilities installed in accordance with this Service Schedule 3 will be owned, operated, and maintained by Company.

RESIDENTIAL

3. Residential Single Family Homes

- 3.1** Extension Facilities will be installed to new Permanent residential applicants or groups of new Permanent residential applicants on a free footage basis under the following conditions:
- (A) A Line Extension Agreement signed by the applicant and construction costs in excess of the allowances, as described in 3.1(C) and 3.2 will be paid by the applicant before the Company begins installing facilities. Payment is due at the time the Line



SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

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- Extension Agreement is signed by the applicant.
- (B) The site plan has been approved and recorded in the county having jurisdiction.
 - (C) The total footage of the Extension Facilities (primary, secondary, service) does not exceed 750 feet per applicant or \$10,000; or
 - (D) The total cost of the Extension Facilities, as determined by Company, is less than \$10,000 per applicant.
- 3.2 All additional construction costs over \$10,000 per applicant will be paid by applicant as a non-refundable contribution in aid of construction.
- 3.3 Applicants who combine to form a group may also combine their allowance as specified in Sections 3.1(C) and 3.2.
- 3.4 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project which will exclude the cost of one single-phase transformer.
- 3.5 The footage allowance of 750 feet and the cap of \$10,000 will be reviewed from time to time with the Arizona Corporation Commission.
- 3.6 Examples of the application of Section 3.1 can be found in Attachment 2 – Free Footage Illustrative Example.

4. Residential Subdivision Developments

- 4.1 Extension Facilities will be installed to Residential Subdivision Developments of four or more homes in advance of application for service by Permanent customers under the following conditions:
- (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of construction by the Company. Payment is due at the time the Line Extension Agreement is signed by the applicant.
 - (B) The subdivision development plat has been approved and recorded in the county having jurisdiction. Applicant is responsible for providing Company an approved subdivision plat prior to project design. If final approved plat is different from what was originally submitted to Company it may cause delays and additional cost for redesign.
- 4.2 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.



SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

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- 4.3 A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per lot" allowance provisions of Section 4.6 and in accordance with Section 2.4.
 - 4.4 In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond based on the financial condition, or organizational structure of developer.
 - 4.5 That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as street lights.
 - 4.6 The refundable advance will be eligible for refund based on a "per lot" allowance of \$3,500 for each Permanently connected residential customer over a five year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement with the applicant. A review of the project will be conducted annually to determine subdivision buildout, and if the qualifications have been met for any refunds.
 - 4.7 Examples of the application of Section 4 can be found in Attachment 3 – Residential Subdivision Illustrative Example.

5. Residential "Lot Sale" Developments

- 5.1 Extension Facilities will be installed to Residential "Lot Sale" Developments in advance of application for service by Permanent applicants under the following conditions:
 - (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
 - (B) The development plat has been approved and recorded in the county having jurisdiction.
- 5.2 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.
- 5.3 The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.
- 5.4 Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to



Appendix N
Page 8 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.

- 5.5 Extension Facilities will be installed to individual applicants in accordance with provisions listed in Section 3.

6. Master Planned Community Developments

- 6.1 Extension Facilities will be installed to Master Planned Community Developments in advance of application for service by Permanent applicants under the following conditions:
- (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
 - (B) The site development plan has been approved and recorded in the county having jurisdiction.
- 6.2 The cost of extending service to applicant will be determined by a Project-Specific Cost Estimate based on the scope of the project.
- 6.3 The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.
- 6.4 Extension Facilities will be installed to each subdivided tract within the planned development in accordance with the applicable sections of this Service Schedule 3.

7. Residential Multi-Family Developments

- 7.1 Extension Facilities will be installed to Residential Multi-Family Developments in advance of application for service by Permanent customers under the following conditions:
- (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
 - (B) The site development plan has been approved and recorded in the county having jurisdiction.
- 7.2 The cost of extending service to applicant will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost estimate depending on the scope of the project.



SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

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- 7.3 A portion of the project cost will be designated as a refundable advance and will be eligible for refund based on the "per unit" refundable allowance provisions of Section 7.6 and in accordance with Section 2.4.
- 7.4 In lieu of a cash payment for the refundable advance amount, the Company will reserve the right to accept an alternative financial instrument, such as a Letter of Credit or Surety Bond based on the financial condition, or organizational structure of applicant.
- 7.5 That portion of the project cost in excess of the refundable advance will be non-refundable in addition to any other non-standard construction charges such as street lights etc.
- 7.6 The refundable advance will be eligible for refund based on a "per unit" allowance of \$1,000 for each new meter, installed for a permanent residential structure, over a five year period. Refunds of refundable advances will be governed by Section 2.4. The refund eligibility period will be five years which will start three months from the date Company executes the Line Extension Agreement. A review of the project will be conducted annually to determine buildout and if the qualifications have been met for any refunds.

GENERAL SERVICE

8 General Service Provisions

- 8.1 Extension Facilities that do not meet the requirements under Residential Sections 3, 4, 5, 6, or 7 will be considered General Service and will be installed to all applicants who meet the qualifications under Sections 9, 10, 11, 12, 13, or 14 of this Service Schedule 3.

9 Basic General Service

- 9.1 Extension Facilities will be installed to Basic General Service in advance of application for service by Permanent applicants under the following conditions:
- (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
 - (B) The site development plan for the project for which the Line Extension has been requested has been approved and recorded in the county having jurisdiction.
- 9.2 The project costs for Basic General Service installations will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or a combination of Schedule of Charges and Project-Specific Cost Estimate depending on the scope of the project.



Appendix N
Page 10 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

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- 9.3 The cost for Extension Facilities installed for applicants with estimated demand loads of less than three megawatts or less than 3,000 kVA of transformer capacity, will be determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.
- 9.4 The cost for Extension Facilities installed for applicants with projected loads of three megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/ additional equipment for enhanced reliability will be determined by the Company based on Project-Specific Cost Estimates.
- 9.5 Economic Feasibility Analysis for Basic General Service Applicants - Applicants who's Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:
- (A) Project Cost \$25,000 or less - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is \$25,000 or less will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments) multiplied by six is equal to or greater than the cost of the applicant's Extension Facilities.
 - (B) Project Cost greater than \$25,000 - Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than \$25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.
 - (C) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.
 - (D) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of



Appendix N
Page 11 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.

- (E) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10 High Rise Developments

- 10.1 Extension Facilities will be installed to High Rise Developments in advance of application for service by Permanent applicants under the following conditions:
- (A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
 - (B) The site development plan has been approved and recorded in the county or city having jurisdiction.
 - (C) The residential units are individually metered or master metered in accordance with Section 21.
 - (D) Extension Facilities will be installed to designated points of delivery in accordance with APS's Electric Service Requirements Manual (ESRM). It is the applicant's responsibility to provide and maintain the electrical facilities within the building.
- 10.2 The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate, and will be paid by the applicant before Company installing facilities.
- 10.3 Economic Feasibility Analysis for High Rise Developments - Applicants who's Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:
- (A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other non-standard construction charges) is greater than \$25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.
 - (B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual



Appendix N
Page 12 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.

- (C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.
- (D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

10.4 Before Company orders specialized materials or equipment required to provide service, applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

11 Mixed-Use Developments

- 11.1 Extension Facilities will be installed to Mixed-Use Developments in advance of application for service by Permanent applicants under the following conditions:
- (A) A Line Extension Agreement is signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
- (B) The site development plan has been approved and recorded in the county or city having jurisdiction.
- (C) The residential units are individually metered or master metered in accordance with Section 21.
- 11.2 The charges for Extension Facilities will be determined based on a Project-Specific Cost Estimate, and will be paid by the applicant before Company installing facilities.
- 11.3 Economic Feasibility Analysis for Mixed-Use Developments - Applicants who's Extension Facilities are installed on the basis of an Economic Feasibility analysis which determines that the estimated installation cost of the Extension Facilities is not supported by the applicant's estimated delivery service revenue may be required to advance sufficient funds to make installation of the Extension Facilities economically feasible. Company reserves the right to collect a full advance from the applicant based on the project scope, location, applicant's financial condition or organizational structure of the applicant. The following conditions will apply to Economic Feasibility projects:
- (A) Economic Feasibility for projects where the applicant's Extension Facilities cost (excluding non-refundable applicant contributions such as street lights and other



Appendix N
Page 13 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

non-standard construction charges) is greater than \$25,000 will be established where the estimated annual revenue based on Company's then currently effective rate for delivery service (excluding taxes, regulatory assessment and other adjustments), less the cost of service, provides an adequate rate of return on the investment made by Company to serve the applicant.

- (B) Applicants whose Economic Feasibility analysis results in the requirement for a payment in advance of construction may be eligible for a refund of such advance over the term of the Line Extension Agreement's five-year period if the actual annual delivery service revenue for the applicant's project exceeds the estimated delivery service revenue used in the Economic Feasibility analysis.
- (C) The Economic Feasibility analysis for the Extension Facilities will be reviewed at the end of the third and fifth year of the Line Extension Agreement based on actual delivery service revenue for the preceding year and to the degree that actual revenue supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance. Any unrefunded balance remaining five years from the date of the Company's executed Line Extension Agreement will become a non-refundable contribution in aid of construction.
- (D) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.

- 11.4 Before Company orders specialized materials or equipment required to provide service applicant will be required to make an advance payment to the Company for the estimated cost of the material or equipment in accordance with Section 27.2.

12 Corporate Business & Industrial Park Developments

- 12.1 Extension Facilities will be made to Corporate Business and Industrial Park Developments in advance of application for service by Permanent customer under the following conditions:
- (A) A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
 - (B) The site development plan has been approved and recorded in the county or city having jurisdiction.
- 12.2 The cost of installing Extension Facilities will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a project-specific cost estimate depending on the scope of the project.
- 12.3 The cost for Extension Facilities installed for applicants with estimated demand loads of less than three megawatts or less than 3,000 kVA of transformer capacity, will be



Appendix N
Page 14 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

determined in accordance with the Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.

- 12.4 The cost for Extension Facilities installed for applicants with projected loads of three megawatts or greater, requiring transformer capacity of 3,000 kVA and greater, special requests involving primary metering, or specialized/additional equipment for enhanced reliability will be determined by the Company based on Project-Specific Cost Estimates.
- 12.5 The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.
- 12.6 Company will provide a "Conduit Only Design" provided applicant makes a payment in the amount equal to the estimated cost of the preparation of the design, in addition to the costs for any materials, field survey and inspections that may be required. Future extensions in the development will be required to follow the original design plan.
- 12.7 Extension Facilities will be installed to individual lots (at the request of an applicant) within the Corporate Business and Industrial Park Development in accordance with the applicable sections of this Service Schedule 3.

13 Temporary Applicants

- 13.1 Where Temporary Extension Facilities are required to provide service to the applicant, the applicant will make a non-refundable payment in advance of installation or construction equal to the cost of installing and removing of the facilities required in providing Temporary service, less the salvage value of such facilities. Charges will be determined by Company based on a Project-Specific Cost Estimate.
- 13.2 A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.
- 13.3 When use of the Temporary service is discontinued or service is terminated, Company may dismantle and remove its facilities and the materials and equipment provided by Company will remain Company property.

14 Doubtful Permanency Customers

- 14.1 When, in the opinion of Company, Permanency of the applicant's residence or operation is doubtful, the applicant will be required to pay the total cost of the Extension Facilities. The cost of extending service to applicant will be determined in accordance with the



Appendix N
Page 15 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

Schedule of Charges or combination of Schedule of Charges and a Project-Specific Cost Estimate. The applicant will pay the total project estimated cost as a non-refundable contribution in aid of construction in addition to costs for street lights and other non-standard construction charges.

- 14.2 A Line Extension Agreement signed by the applicant and advance payment of all project costs is required before the start of Company construction. Payment is due at the time the Line Extension Agreement is signed by the applicant.

OTHER CONDITIONS

15 Municipalities and Other Governmental Agencies

- 15.1 Extension Facility installations, relocations, or conversions of existing facilities required to serve loads of municipalities or other governmental agencies may be constructed before the receipt of a signed Line Extension Agreement. However, this does not relieve the municipality or governmental agency of the responsibility for payment of the Extension Facilities costs in accordance with the applicable sections of this Service Schedule 3.
- 15.2 The effective date for projects enacted under this provision for purposes of refunds (Section 2.4) will be the date the municipality or agency provided written approval to the Company to proceed with construction.

16 Change in Applicant's Service Requirements

- 16.1 Company will rebuild, modify, or upgrade its existing facilities to meet the applicant's added load, service entrance upgrade, or change in service requirements on the basis specified in Sections 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, or 14. Charges for such changes will be in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a Project-Specific Cost Estimate determined by the Company based on project-specific requirements.

17 Relocations, Conversions and Upgrades of Company Facilities

- 17.1 **Relocations** - Company will relocate its facilities at the applicant's request. The cost of relocations not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.
- (A) When the relocation of Company facilities involves "prior rights" conditions, the applicant will be required to make payment equal to the estimated cost of relocation as a non-refundable contribution in aid of construction. In addition, applicant will be required to provide similar "rights" for the relocated facilities.
- (B) Payment of all project costs is required prior to the start of Company construction.



Appendix N
Page 16 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

Payment is due at the time the Line Extension Agreement is signed by applicant.

17.2 **Conversions** - Company will convert from overhead to underground its facilities at applicant request. The cost of conversions not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate and may include residual value costs as computed in accordance with the method described in A.R.S. Section 40-347.

(A) The applicant will be required to make a payment equal to the estimated cost of conversion as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction.

Payment is due at the time the Line Extension Agreement is signed by the applicant.

17.3 **Upgrades** - Company will upgrade its facilities at applicant request. The cost of Company facility upgrades not in conjunction with a new extension or existing customer upgrade will be determined by a Project-Specific Cost Estimate.

(A) The applicant will be required to make a payment equal to the estimated cost of the upgrade as a non-refundable contribution in aid of construction.

(B) Payment of all project costs is required prior to the start of Company construction.

Payment is due at the time the Line Extension Agreement is signed by the applicant.

18 Additional Primary Feed or Specialized Equipment

18.1 When specifically requested by an applicant to provide an alternate primary feed or specialized equipment (excluding transformation), Company will perform a special study to determine the feasibility of the request. The applicant will be required to pay for the cost of the additional feed requested as a non-refundable contribution in aid of construction. Installation cost will be based on a Project-Specific Cost Estimate. Payment for the installation of Extension Facilities is due at the time the Line Extension Agreement is signed by the applicant.

19 Unusual Circumstances

19.1 In unusual circumstances as determined by Company, when the application and provisions of this Service Schedule 3 appear impractical, or in case of extension of lines to be operated on voltages other than specified in the applicable rate schedule, or when applicant's estimated demand load will exceed 3,000 kW, Company may make a special study of the conditions to determine the basis on which service may be provided. Additionally, Company may require special contract arrangements as provided for in the Company's Service Schedule 1, Terms and Conditions for Standard Offer and Direct Access Service.



Appendix N
Page 17 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

20 Abnormal Loads

- 20.1 Company, at its option, may install Extension Facilities to serve certain abnormal loads (such as: transformer type welders, x-ray machines, wind machines, excess capacity for test purposes and loads of unusual characteristics) and the costs of any distribution system modifications or enhancements required to serve the applicant will be included in the payment described in previous sections of this Service Schedule 3.

21 Master Metering

- 21.1 **Mobile Home Parks** - Company will refuse service to all new construction or expansion of existing Permanent residential mobile home parks unless the construction or expansion are individually metered by Company.
- 21.2 **Residential Apartment Complexes, Condominiums** - Company will refuse service to all new construction of apartment complexes and condominiums which are master metered unless the builder or developer can demonstrate that the installation meets the provisions of R14-2-205 of the Arizona Administrative Code and the requirements discussed in 21.3 below. This section is not applicable to Senior Care/Nursing Centers registered with the State of Arizona with independent living units which provide packaged services such as housing, food, and nursing care.
- 21.3 **Multi-Unit High Rise Residential Developments** - Company will allow master metering for high rise residential units under the following conditions:
- (A) The building will be served by a centralized heating, ventilation or air conditioning system
 - (B) Each residential unit will be individually sub-metered and responsible for energy consumption of that unit.
 - (C) Sub-metering will be provided and maintained by the builder or homeowners association.
 - (D) Responsibility and methodology for determining each unit's energy billing will be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company before Company installing Extension Facilities.
- 21.4 **Conversion from Master Meter to Individually Metered System** - Company will convert its facilities from a master metered system to a Permanent individually metered system at the applicant's request provided the applicant makes a non-refundable contribution in aid of construction equal to the residual value plus the removal costs less salvage of the master meter facilities to be removed. The new facilities to serve the



SERVICE SCHEDULE 3

**CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES**

individual meters will be extended in accordance with the applicable sections of this Service Schedule 3. Applicant is responsible for all costs related to the installation of new service entrance equipment.

22 Voltage

- 22.1 All Extension Facility installations will be designed and constructed for operation at standard voltages used by Company in the area in which the Extension Facilities are located. At the request of applicant, Company may, at its option, deliver service for special applications of non-standard or higher voltages with prior approval from Company's Engineering Department. Applicant will be required to pay the costs of any required studies as a non-refundable payment.
- 22.2 Extension Facilities installed at higher voltages will be limited to serving an applicant operating as one integral unit under the same name and as part of the same business on adjacent and contiguous sites not separated by private property owned by another party or separated by public property or public right-of-way.

23 Point of Delivery

- 23.1 For overhead service, the point of delivery will be where Company's service conductors terminate at the applicant's weatherhead or bus riser.
- 23.2 For underground service, the point of delivery will be where Company's service conductors terminate in the applicant's or development's service equipment. The applicant will furnish, install and maintain any risers, raceways and termination cabinets necessary for the installation of Company's underground service conductors.
- 23.3 For special applications where service is provided at voltages higher than the standard voltages specified in the APS Electric Service Requirements Manual, Company and applicant will mutually agree upon the designated point of delivery.

24 Easements

- 24.1 Before Company begins construction of Extension Facilities, all suitable easements and rights-of-way required for any portion of the extension, will be obtained by applicant and provided to Company in Company's name without cost to, or condemnation by Company. All easements and rights-of-way obtained on behalf of Company will be on Company's standard easement form which contains the terms and conditions that are acceptable to Company.

25 Grade Modifications



Appendix N
Page 19 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

- 25.1 If after construction of Extension Facilities, the final grade of the property established by the applicant is changed in such a way as to require relocation of Company facilities, or the applicant's actions or those of his contractor results in damage to such facilities, the cost of replacement, relocation, or any resulting repairs will be borne by applicant as a non-refundable contribution in aid of construction.

26 Measurement and Location

- 26.1 Measurement must be along the proposed route of construction.
- 26.2 Construction will be on public streets, roadways, highways, or easements acceptable to Company.
- 26.3 Extension Facilities must be a branch from, the continuation of, or an addition to, Company's existing distribution facilities.

27 Agreements

- 27.1 **Study and Design Agreements** - Any applicant requesting Company to prepare special studies or detailed plans, specifications, or cost estimates will be required to make a payment to Company in an amount equal to the estimated cost of preparation. When the applicant authorizes Company to proceed with construction of the Extension Facilities, the payment will be credited to the cost of the Extension Facilities otherwise the payment will be non-refundable. Company will prepare, without charge, a preliminary sketch and rough estimate of the cost to be paid by the applicant upon request.
- 27.2 **Material Order Agreements** - Any applicant requesting Company to enter into a Line Extension Agreement, or relocation agreement which requires either large quantities of material or material and equipment which the Company does not keep in stock will be required to make a payment to Company before the material being ordered in an amount equal to the material/equipment's estimated cost. When the applicant authorizes Company to proceed with construction of the extension, the payment will be credited to the cost of the extension; otherwise the payment will be non-refundable.
- 27.3 **Line Extension Agreements** - All facility installations or equipment upgrades requiring payment by an applicant will be in writing and signed by both the applicant and Company.

28 Applicant Construction of Company Distribution Facilities



SERVICE SCHEDULE 3

**CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES**

-
- 28.1 Applicant may provide construction related labor only services associated with the installation of new distribution line facilities (21 kV and below) to serve the applicant's new or added load provided the applicant receives written approval from Company before performing any such services and uses electrical contractors who are qualified and licensed in the State of Arizona to construct such facilities and designated as an APS Approved Electrical Distribution Contractor.
- 28.2 This option is not available for the following:
- (A) Replacement, modifications, upgrades, relocation, or conversions of existing systems.
 - (B) Where all or a portion of the distribution line facilities are to be constructed on or installed on existing distribution line or transmission lines.
- 28.3 All construction services provided by the applicant will be subject to inspection by a duly authorized Company representative and will comply with Company designs, construction standards, and other requirements which may be in effect at the time of construction. Any work found to be substandard in the sole opinion of the Company must be corrected by applicant before energization by Company.
- 28.4 Applicant will reimburse Company for all inspection and project coordination costs as a non-refundable contribution in aid of construction. Estimated costs for inspection and project coordination will be identified in the construction agreement executed by Company and applicant.
- 28.5 Costs for Extension Facilities for applicants who provide construction of Company distribution facilities will be based on a Project-Specific Cost Estimate.
- 28.6 A signed agreement and payment of all project costs minus labor are required before the start of applicant construction. Payment is due at the time the agreement is signed by the applicant.
- 28.7 For applicants that are not served by the terms in General Service Sections of this document, Company will provide a Project-Specific Cost Estimate. Applicants may submit an invoice detailing costs of Extension Facilities and apply any allowance provided in Residential Sections 3, 4, or 7 to these costs. At no point will these costs exceed the Company's Project-Specific Cost Estimate.
- 28.8 Applicants served by the terms in General Service Sections 9, 10, 11, 12, 13, or 14 of this document will be subject to the rules set forth in the respective section and Refund Section 2.4.

29 Settlement of Disputes

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Charles A. Miessner
Title: Manager, Regulation and Pricing
Original Effective Date: January 31, 1954

A.C.C. No. XXXX
Canceling A.C.C. No. 5801
Service Schedule 3
Revision No. 13
Effective: XXXXXXXX



Appendix N
Page 21 of 26

SERVICE SCHEDULE 3

CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

- 29.1 Any dispute between the applicant or prospective applicant and Company regarding the interpretation of these "Conditions Governing Extensions of Electric Distribution Lines and Services" may be referred to the Arizona Corporation Commission or a designated representative or employee for determination by either party.

30 Policy Exceptions

- 30.1 This Schedule 3 is applicable to all applicants unless specific exceptions are approved by the Arizona Corporation Commission. The following exceptions have been approved for Rural Municipality applicants:
- (A) Extension Facilities will be installed to Rural Municipal Business Developments on the basis of an Economic Feasibility analysis in advance of application for service by Permanent applicants.
 - (B) The cost of installing Extension Facilities to Rural Municipal Business Developments will be determined in accordance with the Schedule of Charges, a Project-Specific Cost Estimate, or combination of Schedule of Charges and a Project-Specific Cost Estimate depending on the scope of the project.
 - (C) The refund eligibility period for Rural Municipal Business Developments will be seven years from the date the Company executes the Line Extension Agreement with the Rural Municipality applicant.
 - (D) Rural Municipal Business Development applicants will be required to advance payment of one-half of the project costs at the time the Line Extension Agreement is signed and before the start of Company construction. The balance of the project cost will be required seven years from the Execution Date of the agreement if the project has not become economically feasible by the end of the seven year refundable period. Any unrefunded advance balance paid at the start of the project, plus the balance of project costs due at the end of refund period, will become a non-refundable contribution in aid of construction seven years from the Execution Date of the agreement.
 - (E) Company may require a Surety Bond, Irrevocable Letter of Credit or Assignment of Monies in amount equal to any Advance not collected at the start of construction.
 - (F) The Economic Feasibility analysis for the Rural Municipal Business Development's Extension Facilities will be reviewed at the end of the third, fifth and seventh year of the Line Extension Agreement based on the average monthly demand within the Rural Municipal Business Development for the preceding year and to the degree that the average monthly demand supports the Extension Facilities cost, all or a portion of the applicant's construction advance may be refunded. In no case will refunds exceed the unrefunded balance of the applicant's advance.



-
- (G) Company may include a capacity factor component, as determined by Company, to the Economic Feasibility Analysis for applicants that request excess or redundant system capacity.



Appendix N
Page 23 of 26

SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

Attachment 1
Schedule of Charges - Single Phase

APS Schedule 3 Rev 13, Line Extension Schedule of Charges

Single Phase	OH Primary	UG Primary				OH Secondary		UG Secondary	
		Cost per Circuit Foot	Pull Box	Pad Mount Junction Cabinet	OH/UG Transition	Secondary Pole	OH/UG Secondary Transition	J Box	
	Cost per Circuit Foot	\$5.64	\$898	\$3,889	\$1,346	\$2,259	\$892.22	\$105.55	
	Each Installation								
Pole Intersect	\$10,251.54								
OVERHEAD Single Phase	SES Size	Transformer Size, 120/240V				Service wire/Linear Ft			
	200 Amp	25kVA	\$3,853	\$6.15					
	200 Amp	50kVA	\$4,178	\$7.90					
	400 Amp	50kVA	\$4,178	\$7.90					
	600 Amp	75kVA	\$5,249	\$13.06					
	800 Amp	100kVA	\$6,057	\$18.23					
UNDERGROUND Single Phase	SES Size	Transformer Size, 120/240V				Service wire/Linear Ft			
	200 Amp	25kVA	\$4,266	\$5.22					
	200 Amp	50kVA	\$4,657	\$6.66					
	400 Amp	50kVA	\$4,657	\$6.66					
	600 Amp	75kVA	\$5,229	\$13.46					
	800 Amp	100kVA	\$5,984	\$14.91					
1) Extension Facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.									
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will be summed to determine charges.									
3) Pad Mount Junction Cabinet is a single phase termination cabinet.									
4) Primary OH cost per foot is for one phase and a neutral or two phases and no neutral; includes poles, framing, 2R conductor									
5) Charges for services are based on linear footage from Transformer to SES regardless of the number of sets. J Boxes not included in footage cost.									
6) All footages to be calculated by linear footages.									
7) Transition is from the OH line to the UG line; includes wire down pole and accessories. Pole NOT included.									

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Charles A. Miessner
Title: Manager, Regulation and Pricing
Original Effective Date: January 31, 1954

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Service Schedule 3
Revision No. 13
Effective: XXXXXXXX



SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

Attachment 1
Schedule of Charges – Three Phase

APS Schedule 3 Rev 13, Line Extension Schedule of Charges

FEEDER Three Phase	Overhead				Underground				Pad Mount Switch Gear	Manhole (6-750)	Cost per Circuit Foot (6-750) Each Installation	Cost per Circuit Foot 1100A Cable (3-1100) Each Installation	Cost per Circuit Foot 1100A Cable (6-1100) Each Installation
	Cost per Circuit Foot (3-750)	Each Installation	Pull Box (3-750)	Manhole (3-750)	Cost per Circuit Foot (6-750)	Pull Box (6-750)	Manhole (6-750)	Each Installation					
OH/UG Transition	\$29.31	\$24.36	\$4,694	\$13,345	\$48.08	\$8,435	\$19,144	\$17,981	\$17,981	\$19,144	\$27.63	\$27.63	\$54.63
Pole Intersect		\$6,566			\$7,947			\$6,903				\$6,903	\$8,021
PRIMARY Three Phase	Overhead				Underground								
OH/UG Transition	Cost per Circuit Foot (3-10T)	Cost per Circuit Foot (3-40T)	Pull Box		Pad Mount Switch Gear								
	\$22.18	\$16.80	\$19.91	\$1,647	\$17,981								
Pole Intersect		\$3,004	\$3,100										
OVERHEAD Three Phase	Overhead				Overhead								
	SES Size	Transformer Size 120/208 Volts	Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts	Service wire/Linear Ft						
	200 Amp	3-25KVA	\$9,047	\$6.29	200 Amp	3-50KVA	\$12,069	\$6.29					
	400 Amp	3-50KVA	\$10,422	\$6.29	400 Amp	3-75KVA	\$14,064	\$8.19					
	600 Amp	3-50KVA	\$10,422	\$8.19	600 Amp	3-100KVA	\$15,939	\$10.42					
	800/1000 Amp	3-75KVA	\$13,619	\$19.69	800 Amp	3-167KVA	\$18,181	\$10.42					
	SES Size	Transformer Size 120/208 Volts	Service wire/Linear Ft		SES Size	Transformer Size 277/480 Volts	Service wire/Linear Ft						
	200 Amp	112.5KVA	\$8,337	\$7.12	200 Amp	112.5KVA	\$11,080	\$7.12					
	400 Amp	112.5KVA	\$8,337	\$12.73	400 Amp	150KVA	\$12,334	\$12.71					
	600 Amp	150KVA	\$12,495	\$18.08	600 Amp	225KVA	\$13,445	\$22.86					
	800 Amp	225KVA	\$13,907	\$36.16	800 Amp	300KVA	\$15,042	\$36.09					
	1000 Amp	225KVA	\$13,907	\$36.16	1000 Amp	500KVA	\$17,145	\$36.09					
	1200 Amp	300KVA	\$15,181	\$36.16	1200 Amp	500KVA	\$17,145	\$36.09					
	1600 Amp	500KVA	\$19,438	\$72.04	1600 Amp	750KVA	\$21,376	\$54.01					
	2000 Amp	500KVA	\$19,438	\$72.04	2000 Amp	1000KVA	\$24,378	\$72.04					
	2500 Amp	750KVA	\$25,603	\$126.10	2500 Amp	1000KVA	\$24,383	\$72.04					
	3000 Amp	750KVA	\$25,613	\$126.10	3000 Amp	1500KVA	\$34,903	\$108.09					
	3000 Amp	1000KVA	\$30,638	\$162.05	3000 Amp	2000KVA	\$42,539	\$182.05					

- 1) Extension facilities that do not qualify for the Schedule of Charges will be determined by a project specific cost estimate.
2) Cost per foot charges will be determined from termination at the source to the next device in the circuit. Linear footage for each circuit will be summed to determine charges.
3) For Multiple services out of one three phase transformer, the service cost will be determined by each SES and the transformer cost will be determined from the combined total of each SES size in amps, rounded up to the nearest SES size, limited to a combined maximum of 3,000 amps.
4) Overhead feeder cost per foot is for 30 and above, including 477 & 795 conductors.
5) UG Primary circuit footage is 3 cables making up 3 phase, 2 circuits is parallel conductors.
6) Charges for services are based on linear footage from transformer to SES regardless of the number of sets.
7) Transition is from the OH line to the UG line, includes wire down pole and accessories. Pole NOT included.

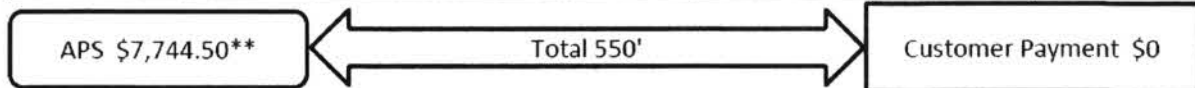


Appendix N
Page 25 of 26

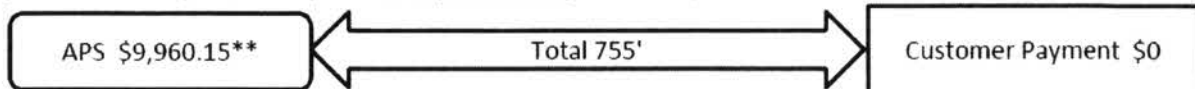
SERVICE SCHEDULE 3
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES

Attachment 2
Examples to Section 3* - Free Footage Illustrative Example

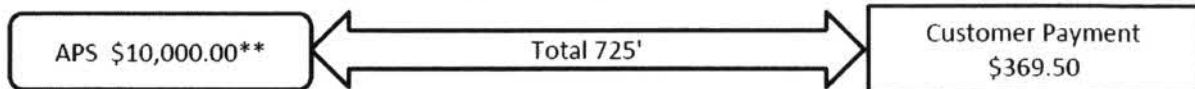
	Primary		Service		Total		Customer Payment
	Footage	Cost	Footage	Cost	Footage	Cost	
Scenario 1	500	\$15.00	50	\$ 4.89	550	\$ 7,744.50	\$ -



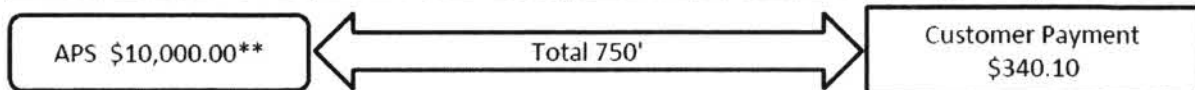
	Primary		Service		Total		Customer Payment
	Footage	Cost	Footage	Cost	Footage	Cost	
Scenario 2	620	\$ 15.00	135	\$ 4.89	755	\$ 9,960.15	\$ -



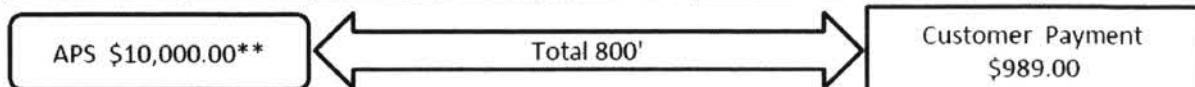
	Primary		Service		Total		Customer Payment
	Footage	Cost	Footage	Cost	Footage	Cost	
Scenario 3	675	\$ 15.00	50	\$ 4.89	725	\$ 10,369.50	\$ 369.50



	Primary		Service		Total		Customer Payment
	Footage	Cost	Footage	Cost	Footage	Cost	
Scenario 4	660	\$ 15.00	90	\$ 4.89	750	\$ 10,340.10	\$ 340.10



	Primary		Service		Total		Customer Payment
	Footage	Cost	Footage	Cost	Footage	Cost	
Scenario 5	700	\$ 15.00	100	\$ 4.89	800	\$ 10,989.00	\$ 989.00



*Scenarios do not reflect all components required for a complete project.

**APS portion does not include cost of transformer.

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
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Title: Manager, Regulation and Pricing
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**SERVICE SCHEDULE 3**
CONDITIONS GOVERNING EXTENSIONS OF
ELECTRIC DISTRIBUTION LINES AND SERVICES**Attachment 3**
Residential Subdivision Illustrative Example

Scenario 1	
Number of Planned Homes	100
Estimated Construction Cost	\$ 350,000
Total Potential Refundable Allowance	\$ 350,000
Non-Refundable Contribution	\$ -
Number of Homes Completed	100
Credited Allowance	\$ 350,000
Potential Remaining Allowance	\$ -

Scenario 2	
Number of Planned Homes	100
Estimated Construction Cost	\$ 400,000
Total Potential Refundable Allowance	\$ 350,000
Non-Refundable Contribution	\$ 50,000
Number of Homes Completed	100
Credited Allowance	\$ 350,000
Potential Remaining Allowance	\$ -

Scenario 3	
Number of Planned Homes	100
Estimated Construction Cost	\$ 350,000
Total Potential Refundable Allowance	\$ 350,000
Non-Refundable Contribution	\$ -
Number of Homes Completed	45
Credited Allowance	\$ 157,500
Potential Remaining Allowance	\$ 192,500

Scenario 4	
Number of Planned Homes	100
Estimated Construction Cost	\$ 400,000
Total Potential Refundable Allowance	\$ 350,000
Non-Refundable Contribution	\$ 50,000
Number of Homes Completed	45
Credited Allowance	\$ 157,500
Potential Remaining Allowance	\$ 192,500

Appendix O

**Lost Fixed Cost Recovery
Plan of Administration**

Effective Date: XXXX

Table of Contents

1. General Description.....	1
2. Definitions.....	1
3. LFCR Annual Incremental Cap.....	3
4. Historical Transition.....	3
5. Filing and Procedural Deadlines.....	3
6. Compliance Reports.....	3

1. General Description

This document describes the plan of administration for the Lost Fixed Cost Recovery (LFCR) mechanism approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on XX/XX/XXX in Decision No. XXXXX. The LFCR mechanism provides for the recovery of lost fixed costs authorized by the Commission, as measured by revenue, associated with the amount of energy efficiency (EE) savings and distributed generation (DG) determined to have occurred. Costs to be recovered through the LFCR include the portion of distribution costs included in base rates, less what is already recovered by 50% of demand revenues associated with distribution.

2. Definitions

Applicable Company Revenues – The amount of revenue generated by sales to retail customers, for all applicable rate schedules.

Current Period – The most recent adjustment year.

DG Savings – The amount of MWh sales reduced by DG. APS will use meter data to calculate DG system savings where available. Each year, APS will use actual data from January through September and forecast data for the remainder of the calendar year (October through December) to calculate the savings. The calculation of DG Savings will consist of the following by class:

- a. **Current Period:** The annual energy production (MWh) produced by the cumulative total of DG installations since the effective date of APS's most recent general rate case.
 - b. **Excluded MWh Production:** The reduction of recoverable DG Savings calculated for commercial and industrial customers, by subtracting the amount of DG produced by customers on Excluded Rate Schedules.
 - c. **True-Up Prior Period:** The reconciliation of APS's forecast data of DG sales reductions for the three months in the Prior Period to verified DG sales reductions in the Prior Period.
-

EE Programs – Any program approved in APS’s annual implementation plan.

EE Savings – The amount of MWh sales reduced by EE as demonstrated by the Measurement, Evaluation, and Research (MER) conducted for EE Programs. The calculation of EE Savings will consist of the following by class:

- a. Cumulative Verified: The cumulative total MWh reduction as determined by the MER using the effective date of APS’s most recent general rate case as a starting point.
- b. Current Period: The annual EE related sales reductions (MWh). Each year, APS will use actual pre-MER verified data through November and forecast data for December to calculate annual savings.
- c. Excluded MWh reduction: The reduction of recoverable EE Savings calculated for commercial and industrial customers, by subtracting the amount of EE Savings actually achieved by customers on Excluded Rate Schedules.
- d. True-Up Prior Period: The reconciliation of APS’s forecast data of annual EE sales reductions for the Prior Period to the MER verified EE sales reductions in the Prior Period.

Excluded Delivery Revenue – 50% of any delivery demand (kW) revenue as determined in Decision No. XXXXX and calculated on Schedules 6 and 7.

Excluded Rate Schedules – The LFCR mechanism will not apply to large general service customers taking service under rate schedules E-32 L, E-32 L TOU, E-34, E-35, XHLF and E-36 XL, or to unmetered General Service customers under E-30 and lighting schedules, Contract 12.

LFCR Adjustment – Total Lost Fixed Cost Revenue as calculated on Schedule 2, divided by forecast retail kWh sales for the proposed adjustor period. For customers on a demand rate the adjustment will be applied as a kW charge. For customers on an energy only rate the adjustment will be applied as kWh charge. This adjustment will be applied to all customer bills, with the exception of those customers on Excluded Rate Schedules, or if the customer’s current rate has alternate provisions.

Lost Fixed Cost Rate – A rate determined at the conclusion of APS’s most recent general rate case by taking the sum of allowed Distribution Revenue for each General Service & Residential rate class and dividing each by their respective class adjusted test year kWh billing determinants.

Lost Fixed Cost Revenue – The amount of fixed costs not recovered by the utility because of EE and DG during the calendar year. This amount is calculated by multiplying the Lost Fixed Cost Rate by Recoverable MWh Savings, by rate class.

Prior Period – The 12 months preceding the Current Period.

Recoverable MWh Savings – The sum of EE Savings and DG Savings by rate class.

Transition Balance – The Lost Fixed Cost Revenue balance as calculated in compliance with the LFCR Plan of Administration applicable during that time period per Decision No. 73183 and modified in Decision No. 74202.

3. LFCR Annual Incremental Cap

The LFCR Adjustment will be subject to an annual 1% year-over-year cap based on Applicable Company Revenues. If the annual LFCR Adjustment results in a surcharge and the annual incremental increase exceeds 1% of Applicable Company Revenues, any amount in excess of the 1% cap will be deferred for collection until the first future adjustment period in which including such costs would not cause the annual increase to exceed the 1% cap. The one-year Treasury Constant Maturities, effective on the first business day each year, as published on the Federal Reserve website or its successor publication will be applied annually to any deferred balance.

4. Historical Transition

Upon implementation of the revised LFCR Plan of Administration in Decision No. XXXXX, the Transition balance will be calculated on Schedule 4 (LFCR Historical Transition) and reported on Schedule 2 (LFCR Annual Incremental Cap Calculation).

5. Filing and Procedural Deadlines

APS will file the calculated LFCR Adjustment, including all Compliance Reports, with the Commission for the previous year by February 15th. The new LFCR Adjustment will not go into effect until approved by the Commission. If approved, the new rate will take effect with the first billing cycle in May, unless otherwise specified by the Commission.

6. Compliance Reports

APS will provide comprehensive Compliance Reports to Staff and the Residential Utility Consumer Office. The information contained in the Compliance Reports will consist of the following schedules:

- Schedule 1: LFCR Annual Adjustment
- Schedule 2: LFCR Annual Incremental Cap Calculation
- Schedule 3: LFCR Calculation
- Schedule 4: LFCR Historical Transition
- Schedule 5: LFCR Test Year Rate Calculation
- Schedule 6: Distribution Revenue Calculation – General Service
- Schedule 7: Distribution Revenue Calculation – Residential
- Schedule 8: Annual DG Installation Report

Schedules 1 through 8, attached hereto, will be submitted with APS's annual compliance filing.

Line No.	(A) Annual Percentage Adjustment	(B) Reference	(C) Total
1.	Total Lost Fixed Cost Revenue for Current Period	Schedule 2, Line 15	\$ -
2.	Applicable Company MWh		-
3.	\$/kWh	Line 1 / Line 2	\$ -
4.	Applicable Company MWh for customer billed demand		-
5.	\$ for Customers Billed Demand	Line 3 * Line 4	\$ -
6.	Applicable Company MW for customer billed demand		-
7.	\$/kW	Line 5 / Line 6	\$ -

Line No.	(A) LFCR Annual Incremental Cap Calculation	(B) Reference	(C) Totals
1.	Applicable Company Revenues		\$ -
2.	Allowed Cap %		1.00%
3.	Maximum Allowed Incremental Recovery	(Line 1 * Line 2)	\$ -
4.	Total Lost Fixed Cost Revenue	Schedule 3, Line 33, Column C	\$ -
4a	Historical Transition	Schedule 4, Line 33, Column C	\$ -
5.	Total Deferred Balance from Previous Period	Previous Filing, Schedule 2, Line 13, Column C	-
6.	Annual Interest Rate		0.00%
7.	Interest Accrued on Deferred Balance	(Line 5 * Line 6)	-
8.	Total Lost Fixed Cost Revenue Current Period	(Line 4 + Line 4a + Line 5 + Line 7)	\$ -
9.	Lost Fixed Cost Revenue from Prior Period	Previous Filing, Schedule 2, Line 15, Column C	\$ -
10a	Lost Fixed Cost Revenue - Billed ¹		\$ -
10b	Rate Rider LFCR DG - Billed ^{1,2}		\$ -
10c	Grid Access - Billed ^{1,2}		\$ -
11.	LFCR Balancing Account	(Line 9 - Line 10)	\$ -
12.	Total Incremental Lost Fixed Cost Revenue for Current Year	(Line 8 - Line 9 + Line 11)	\$ -
13.	Amount in Excess of Cap to Defer	(Line 12 - Line 3)	\$ -
14.	Incremental Period Adjustment as %	[(Line 12 - Line 13) / Line 1]	0.00%
15.	Total Lost Fixed Cost Revenue for Current Period	(Line 8 + Line 11 - Line 13)	\$ -

¹Amount billed to customers for the 12 calendar months of 20XX.

²Excludes amount billed to customers with DG installations prior to 2016.

Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference	(C) Totals	(D) Units
Residential				
Energy Efficiency Savings				
1.	Current Period		-	MWh
2.	Prior Period	Previous Filing, Schedule 3, Line 1, Column C	-	MWh
3.	Verified - Prior Period		-	MWh
4.	True-Up Prior Period	(Line 3 - Line 2)	-	MWh
5.	Cumulative Verified	(Previous Filing, Schedule 3, Line 5, Column C + Line 6)	-	MWh
6.	Total Recoverable EE Savings	(Line 1 + Line 4 + Line 5)	-	MWh
Distributed Generation Savings				
7.	Current Period		-	MWh
8.	Prior Period	Previous Filing, Schedule 3, Line 7, Column C	-	MWh
9.	Verified - Prior Period		-	MWh
10.	True-Up Prior Period	(Line 9 - Line 8)	-	MWh
11.	Total Recoverable DG Savings	(Line 7 + Line 10)	-	MWh
12.	Total Recoverable MWh Savings	(Line 6 + Line 11)	-	MWh
13.	Residential - Lost Fixed Cost Rate	Schedule 5, Line 3, Column C	\$	\$/kWh
14.	Residential - Lost Fixed Cost Revenue	(Line 12 * Line 13)	\$	-
C&I				
Energy Efficiency Savings				
15.	Current Period		-	MWh
16.	Excluded MWh reduction		-	MWh
17.	Net - Current Period	(Line 15 - Line 16)	-	MWh
18.	Prior Period	Previous Filing, Schedule 3, Line 17, Column C	-	MWh
19.	Verified - Prior Period		-	MWh
20.	True-Up Prior Period	(Line 19 - Line 18)	-	MWh
21.	Cumulative Verified	(Previous Filing, Schedule 3, Line 21, Column C + Line 24)	-	MWh
22.	Total Recoverable EE Savings	(Line 17 + Line 20 + Line 21)	-	MWh
Distributed Generation Savings				
23.	Current Period		-	MWh
24.	MWh DG Savings from Rate Schedules Excluded from LFCR		-	MWh
25.	Net - Current Period	(Line 23 - Line 24)	-	MWh
26.	Prior Period	Previous Filing, Schedule 3, Line 25, Column C	-	MWh
27.	Verified - Prior Period		-	MWh
28.	True-Up Prior Period	(Line 27 - Line 26)	-	MWh
29.	Total Recoverable DG Savings	(Line 25 + Line 28)	-	MWh
30.	Total Recoverable MWh Savings	(Line 22 + Line 29)	-	MWh
31.	C&I - Lost Fixed Cost Rate	Schedule 5, Line 6, Column C	\$	\$/kWh
32.	C&I - Lost Fixed Cost Revenue	(Line 30 * Line 31)	\$	-
33.	Total Lost Fixed Cost Revenue	(Line 14 + Line 32)	\$	-

Line No.	(A) Lost Fixed Cost Revenue Calculation	(B) Reference	(C) Totals	(D) Units
Residential				
Energy Efficiency Savings				
1.	Current Period		-	MWh
2.	Prior Period		-	MWh
3.	Verified - Prior Period		-	MWh
4.	True-Up Prior Period	(Line 3 - Line 2)	-	MWh
5.	Cumulative Verified		-	MWh
6.	Total Recoverable EE Savings	(Line 1 + Line 4 + Line 5)	-	MWh
Distributed Generation Savings				
7.	Current Period		-	MWh
8.	Prior Period		-	MWh
9.	Verified - Prior Period		-	MWh
10.	True-Up Prior Period	(Line 9 - Line 8)	-	MWh
11.	Total Recoverable DG Savings	(Line 7 + Line 10)	-	MWh
12.	Total Recoverable MWh Savings	(Line 6 + Line 11)	-	MWh
13.	Residential - Lost Fixed Cost Rate	Decision No. 73183	\$ 0.031111	\$/kWh
14.	Residential - Lost Fixed Cost Revenue	(Line 12 * Line 13)	\$ -	
C&I				
Energy Efficiency Savings				
15.	Current Period		-	MWh
16.	Excluded MWh reduction		-	MWh
17.	Net - Current Period	(Line 15 - Line 16)	-	MWh
18.	Prior Period		-	MWh
19.	Verified - Prior Period		-	MWh
20.	True-Up Prior Period	(Line 19 - Line 18)	-	MWh
21.	Cumulative Verified		-	MWh
22.	Total Recoverable EE Savings	(Line 17 + Line 20 + Line 21)	-	MWh
Distributed Generation Savings				
23.	Current Period		-	MWh
24.	MWh DG Savings from Rate Schedules Excluded from LFCR		-	MWh
25.	Net - Current Period	(Line 23 - Line 24)	-	MWh
26.	Prior Period		-	MWh
27.	Verified - Prior Period		-	MWh
28.	True-Up Prior Period	(Line 27 - Line 26)	-	MWh
29.	Total Recoverable DG Savings	(Line 25 + Line 28)	-	MWh
30.	Total Recoverable MWh Savings	(Line 22 + Line 29)	-	MWh
31.	C&I - Lost Fixed Cost Rate	Decision No. 73183	\$ 0.023190	\$/kWh
32.	C&I - Lost Fixed Cost Revenue	(Line 30 * Line 31)	\$ -	
33.	Total Lost Fixed Cost Revenue	(Line 14 + Line 32)	\$ -	

Line No.	(A) Lost Fixed Cost Rate Calculation	(B) Reference	(C) Total
Residential Customers			
1.	Residential Fixed Revenue	Schedule 7, Line 18, Column G	\$ -
		Schedule 7, Line 17, Column B /	
2.	MWh Billed	1,000	-
3.	Lost Fixed Cost Rate	(Line 1 / Line 2)	\$ -
C & I Customers			
4.	Total Fixed Revenue	Schedule 6, Line 18, Column G	\$ -
		Schedule 6, Line 17, Column B /	
5.	MWh Billed	1,000	-
6.	Lost Fixed Cost Rate	(Line 8 / Line 9)	\$ -

(A)	(B)	(C)	(D)	(E)	(F)	(G)
						C*E*(1-F)
Line No.	Rate Schedule	Tariff Component	Adjusted Test Year Billing Determinants	Units	Delivery Charge	Demand Stability Factor
1.	General Service Rate X					
2.			- kW	\$	-	50% \$
3.			- kWh	\$	-	0% \$
4.		Sub Total	- kW			\$
5.			- kWh			\$
6.	General Service Rate X					
7.			- kW	\$	-	50% \$
8.			- kWh	\$	-	0% \$
9.		Sub Total	- kW			\$
10.			- kWh			\$
11.	General Service Rate X					
12.			- kW	\$	-	50% \$
13.			- kWh	\$	-	0% \$
14.		Sub Total	- kW			\$
15.			- kWh			\$
16.	Total kW		- kW			\$
17.	Total kWh		- kWh			\$
18.	Total					\$

(A)	(B)	(C)	(D)	(E)	(F)	(G)	
						C*E*(1-F)	
Line No.	Rate Schedule	Tariff Component	Adjusted Test Year Billing Determinants	Units	Delivery Charge	Demand Stability Factor	Total Distribution Revenue
1.	Residential Rate X						
2.			-	kW	\$	50%	\$
3.			-	kWh	\$	0%	\$
4.		Sub Total	-	kW			\$
5.			-	kWh			\$
6.	Residential Rate X						
7.			-	kW	\$	50%	\$
8.			-	kWh	\$	0%	\$
9.		Sub Total	-	kW			\$
10.			-	kWh			\$
11.	Residential Rate X						
12.			-	kW	\$	50%	\$
13.			-	kWh	\$	0%	\$
14.		Sub Total	-	kW			\$
15.			-	kWh			\$
16.	Total kW		-	kW			\$
17.	Total kWh		-	kWh			\$
18.	Total						\$

Annual DG Statistics

	20XX	Cummulative beginning 2016
Total Number of Installation		
<5kW		
5kW to 6.5kW		
6.5kW to 10kW		
> 10kW		
Total Installed kW		

Appendix P



Environmental Improvement Surcharge
Plan of Administration

Table of Contents

1. General Description.....	1
2. Definitions	1
3. Qualified FERC Accounts.....	2
4. Calculation of Annual EIS Adjustment.....	2
5. EIS Balancing Account.....	3
6. Filing and Procedural Deadlines	3
7. Compliance Reports.....	3

1. General Description

This document describes the plan for administering the Environmental Improvement Surcharge (EIS) approved for Arizona Public Service Company (APS or Company) by the Arizona Corporation Commission (ACC or Commission) on [insert date] in Decision No. XXXXX. The EIS provides for the recovery of the capital carrying costs effect of actual environmental investments made by APS and not already recovered in base rates approved in Decision No. XXXXX or recovered through another Commission approved adjustment. The EIS will be calculated annually based on the EIS Qualified Investments closed to plant-in-service during the preceding calendar year.

2. Definitions

Annual EIS Adjustment – The Annual EIS Adjustment represents the EIS Capital Carrying Costs on the Qualified Net Plant to be recovered in the subsequent twelve month period and is assessed to customer bills via the EIS \$/kWh rate.

EIS Capital Carrying Costs – EIS Capital Carrying Costs consists of (1) Return on the Qualified Net Plant calculated based on the Company's Weighted Average Cost of Capital (WACC) approved by the Commission in Decision No. XXXXX plus a return on the fair value increment (if any) for the Qualified Net Plant; (2) depreciation expense; (3) income taxes; (4) property taxes and (5) associated operations and maintenance expenses (O&M).

EIS Qualified Investments – Investments in Qualified Environmental Improvement Projects. Each EIS Qualified Investment must: (1) be classified in one or more of the FERC plant accounts as listed in Section 3 of this document, or any other successor FERC account, upon going into service and (2) be tracked by a specific project number.

Fair Value Increment – For purposes of the EIS, the difference between the Fair Value of the EIS Qualified Investments and Qualified Net Plant shall be deemed to be zero.

Qualified Environmental Improvement Projects - Projects designed to comply with established environmental standards required by federal, state, tribal, or local laws and regulations. These standards and criteria for water, waste, and air include but are not limited to limits for carbon dioxide (CO₂), sulfur oxide (SO_x), nitrogen oxide (NO_x), particulate matter (PM), volatile



organic compounds (VOC), and toxics such as mercury (Hg), coal ash management, and requirements under the clean and safe drinking water acts.

Qualified Net Plant – The Qualified Net Plant consists of the EIS Qualified Investments and their associated accumulated depreciation, accumulated deferred income taxes, tax credits and in the event of federal corporate tax reform any related unamortized excess deferred taxes, where applicable.

Total kWh Sales – The total prior calendar year energy (kWh) sales served under applicable ACC jurisdictional electric rate schedules, except Rate Schedules E-36 XL and AG-X as reported in the Company's FERC Form No. 1.

3. Qualified FERC Accounts

1. Steam Production

- FERC Account 310 – Land and Land Rights
- FERC Account 311 – Structures and Improvements
- FERC Account 312 – Boiler Plant Equipment
- FERC Account 313 – Engines and Engine-Driven Generators
- FERC Account 314 – Turbogenerator Units
- FERC Account 315 – Accessory Electric Equipment
- FERC Account 316 – Miscellaneous Power Plant Equipment

2. Nuclear Production

- FERC Account 320 – Land and Land Rights
- FERC Account 321 – Structures and Improvements
- FERC Account 322 – Reactor Plant Equipment
- FERC Account 323 – Turbogenerator Units
- FERC Account 324 – Accessory Electric Equipment
- FERC Account 325 – Miscellaneous Power Plant Equipment

3. Other Production

- FERC Account 340 – Land and Land Rights
- FERC Account 341 – Structures and Improvements
- FERC Account 342 – Fuel Holders, Products, and Accessories
- FERC Account 343 – Prime Movers
- FERC Account 344 – Generators
- FERC Account 345 – Accessory Electric Equipment
- FERC Account 346 – Miscellaneous Power Plant Equipment

Please note this list may expand to include other accounts approved by the ACC in the future.

4. Calculation of Annual EIS Adjustment

The Annual EIS Adjustment is calculated utilizing the accumulation of Qualified Net Plant and calculated EIS Capital Carrying Costs, as defined above and is applied to applicable customers' total bill via a \$/kWh rate over the twelve month period beginning in April of the year following the filing described in Section 6. below. The EIS \$/kWh rate is calculated by dividing the



Annual EIS Adjustment by Total kWh Sales as determined in Schedule 3 of the filing. The EIS rate will not exceed \$0.00050 per kWh.

5. EIS Balancing Account

APS will maintain accounting records that accumulate the difference between the actual allowable Annual EIS Adjustment as compared to the actual revenues received by the Company through the EIS surcharge during the recovery period (April through March). The difference will be recorded to the EIS Balancing Account each month and will be provided annually in Schedule 3 of the filing. In the event that Annual EIS Adjustments are more or less than the revenues collected as of the last billing cycle of March, the over or under collection will be subtracted from or added to the EIS calculation in the subsequent period subject to the overall cap of \$0.00050 per kWh.

6. Filing and Procedural Deadlines

EIS Qualified Projects and the Annual EIS Adjustment calculation will be submitted by the Company to the ACC in the form of Schedules 1 through 3 as attached to this document and described in Section 7. *Compliance Reports*. APS will file the calculated EIS \$/kWh rate including all supporting data, with the Commission for the previous year on or before February 1st.

The Commission Staff and interested parties shall have the opportunity to review the EIS filing and supporting data in the adjustor calculation. Unless the Commission has otherwise acted or Staff has filed an objection by April 1st, the new EIS \$/kWh rate proposed by APS will go into effect with the first billing cycle in April (without proration) and will remain in effect for the following 12-month period.

7. Compliance Reports

APS will provide an annual report to Staff and the Residential Utility Consumer Office detailing all calculations related to the EIS \$/kWh rate. The reports will include the following Schedules 1 through 3 as attached to this document:

- Schedule 1: Qualified Investments for EIS Electric Plant in Service
- Schedule 2: Annual EIS Adjustment Calculation
- Schedule 3: Current Year EIS Cap Calculation and Adjustment

ARIZONA PUBLIC SERVICE COMPANY
Schedule 1 - EIS
 QUALIFIED INVESTMENTS
 ELECTRIC PLANT IN SERVICE
 FOR CALENDAR YEARS 20XX - 20XX

Line No.	(A) Project Tracking Number	(B) Project Name	(C) Purpose	(D) In-Service Date	(E) Total Cost
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
Totals					\$

ARIZONA PUBLIC SERVICE COMPANY

Schedule 2 - EIS

ANNUAL EIS ADJUSTMENT CALCULATION
PLANT IN SERVICE CALENDAR YEARS 20XX-20XX
BILLING PERIOD 4/1/20XX - 3/30/20XX
(Thousands of Dollars)

Line No.	(A) Annual EIS Adjustment Calculation	(B) Reference	(C) Totals
Qualified Plant			
1.	Qualified Environmental Improvement Projects	Schedule 1, Total Line, Column F	\$ -
2.	Accumulated Depreciation		-
3.	Cumulative Deferred Tax/Tax Credits/Excess Deferred Taxes ¹		-
4.	Qualified Net Plant	Line 1 - Line 2 - Line 3	\$ -
5.	Pre-tax Weighted Average Cost of Capital	Decision No. XXXXX	0.0000%
Capital Carrying Cost			
6.	Composite Return on EIS Net Plant	Line 4 * Line 5	\$ -
7.	Annual Depreciation of Plant In Service		-
8.	Applicable Property Tax		-
9.	Associated O&M Expense		-
10.	Total Annual EIS Adjustment	Line 6 + Line 7 + Line 8 + Line 9	\$ -

¹ In the event of a Federal Corporate Tax Rate Change

ARIZONA PUBLIC SERVICE COMPANY
Schedule 3 - EIS
 CURRENT YEAR EIS CAP CALCULATION AND ADJUSTMENT
 PLANT IN SERVICE CALENDAR YEARS 20XX-20XX
 BILLING PERIOD 4/1/20XX - 3/30/20XX
 (Thousands of Dollars)

Page 3 of 3

Line No.	(A) EIS Rate Calculation	(B) Reference	(C) Totals
1.	EIS Adjustment Prior Year	Previous Filing Schedule 2, Line 10	\$ -
2.	EIS Revenue Billed Prior Year		-
3.	EIS Balancing Account	Line 1 - Line 2	\$ -
4.	Current Year Annual EIS Adjustment	Schedule 2, Line 10	\$ -
5.	Total Current Year Annual EIS Adjustment	Line 3 + Line 4	\$ -
6.	Applicable Company Sales, excluding E-36XL and AG-X (kWhs)	FERC Form 1	-
7.	EIS Rate (\$/kWh)	Line 5 / Line 6	\$ -
8.	EIS Rate Cap (\$/kWh)		\$ 0.00050
9.	EIS \$ per kWh Rate Applied to Customer's Bills (\$/kWh)	(Lesser of Line 7 and Line 8)	\$ -

Appendix Q



**Transmission Cost Adjustment
Plan of Administration**

Table of Contents

1. General Description.....	1
2. Calculations	1
3. TCA Balancing Account.....	2
4. Filing and Procedural Deadlines	2
5. Compliance Reports.....	2

1. General Description

The purpose of the Transmission Cost Adjustment (TCA) is to provide a mechanism to recover transmission costs associated with serving retail customers at the level approved by the Federal Energy Regulatory Commission (FERC) and at the same time as new transmission rates become effective for Arizona Public Service (APS or Company) wholesale customers. APS shall file a notice with Docket Control that includes its revised TCA tariff, along with a copy of its FERC information filing of its annual update of transmission service rates pursuant to its Open Access Transmission Tariff (OATT). This notice shall be filed with the Commission at the same time that APS makes its FERC filing.

The TCA applies to APS's Retail Electric Rate Schedules. For Standard Offer customers, the TCA is applied to the bill as a monthly kWh charge for Residential Service Customers and General Service Customers less than or equal to 20 kW. For all other Standard Offer customers, the TCA is applied to the bill as a monthly kW charge. The charge and modifications to it will take effect in billing cycle 1 of the June revenue month without proration.

APS's Network Integration Transmission Service (NITS) is calculated and filed annually with the FERC in accordance with APS's formula rate. The formula rate calculation is specified within the Company's OATT as filed and approved by the FERC.

2. Calculations

The calculated NITS Retail Transmission Rates are shown in Appendix A of the Company's FERC Informational Filing of its Annual Update of transmission service. NITS rates as determined for the following classes:

- Residential Service Customers
- General Service Customers less than or equal to 20 kW
- General Service Customers over 20 kW and less than 3 MW
- General Service Customers equal to and greater than 3 MW

In addition to NITS, APS charges retail customers for other transmission services in accordance with its OATT. These additional ancillary services include:

- Schedule 1 - Scheduling, System Control and Dispatch Service
- Schedule 3 - Regulation and Frequency Response Service
- Schedule 4 - Energy Imbalance Service



Schedule 5 - Operating Reserve-Spinning Reserve Service
Schedule 6 - Operating Reserve - Supplemental Reserve Service

APS's NITS rates will change annually, where ancillary service charges will change only through a separate filing when made by the Company to FERC.

The total APS OATT rate is the sum of the rates for providing these services. The revenue requirement resulting from the FERC APS OATT rate are collected by APS from its retail customers, partly in base rates and the remaining through the TCA rate.

3. TCA Balancing Account

APS will maintain accounting records that accumulate the difference in revenues anticipated to be recovered by the TCA, as compared to the actual revenues received by the Company through the TCA during the recovery period (June through May). The difference will be recorded to the TCA Balancing Account each month and will be provided annually in Attachment C of the filing. In the event the actual TCA revenues for the recovery period (June through the last billing cycle of May) are more or less than the anticipated revenues for that same period, the over or under collection will be subtracted from or added to the TCA balancing account calculation for the subsequent period.

4. Filing and Procedural Deadlines

APS will file the calculated TCA rates with the Commission each year no later than May 15th, in the form of Attachments A through H as attached to this document and described in Section 5. *Compliance Reports*.

The Commission Staff and interested parties shall have the opportunity to review APS's FERC Informational Filing of its Annual Update of transmission service rates pursuant to the APS OATT Attachment H-2, Formula Rate Implementation Protocols. The calculated NITS Retail Transmission Rates are shown in Appendix A of the Company's FERC filing. The new TCA rates proposed by APS will go into effect with the first billing cycle in June (without proration), unless Staff requests Commission review or otherwise ordered by the Commission, and will remain in effect for the following 12-month period.

5. Compliance Reports

APS will provide an annual report to Staff detailing all calculations related to the calculated TCA rates. The reports will include the following Attachments A through H as attached to this document:

Attachment A:	Non-redlined version of the new Adjustment Schedule TCA-1 Revision
Attachment B:	Redlined version of the new Adjustment Schedule TCA-1 Revision
Attachment C:	Numerical inputs used to develop the new TCA-1 rates
Attachment D:	Estimated monthly bill impacts of the new TCA-1 rates
Attachment E:	Table illustrating the percentage demand of each of the classes for the 20XX OATT and 20XX OATT as filed with FERC



**PLAN OF ADMINISTRATION
ADJUSTMENT SCHEDULE TCA
TRANSMISSION COST**

Appendix Q
Page 3 of 35

Attachment F:	Table illustrating the transmission cost embedded in base rates, the current and proposed TCA rates, and the differences in the current and new rates
Attachment G:	Actual and estimated transmission additions, dollars and estimated O&M for calendar years 20XX through 20XX (1 year actual and 2 years forecast)
Attachment H:	APS's Annual Update of transmission service rates pursuant to the APS OATT as filed with FERC

Attachment A

APPLICATION

The Transmission Cost Adjustment ("TCA") charge shall apply to all Standard Offer retail electric schedules. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include a transmission component of base rates that was originally established at \$0.00000 per kilowatt-hour in accordance with A.C.C. Decision No. 67744. Decision No. 67744 also established the TCA. Decision No. 69663 modified the collection of transmission costs in retail rates to tie to the costs found in the FERC approved Open Access Transmission Tariff.

RATE

The charge shall be applied as follows:

Customer Class	TCA Charge
Residential	\$0.000000/kWh
General Service 20 kW or less	\$0.000000/kWh
General Service over 20 kW, under 3,000 kW	\$0.000/kW
General Service 3,000 kW and over	\$0.000/kW

APPLICATION

The Transmission Cost Adjustment ("TCA") charge shall apply to all Standard Offer retail electric schedules. All provisions of the customer's current applicable rate schedule will apply in addition to this charge.

ANNUAL ADJUSTMENT

Standard Offer rate schedules covered by this charge include a transmission component of base rates that was originally established at \$0.00000 per kilowatt-hour in accordance with A.C.C. Decision No. 67744. Decision No. 67744 also established the TCA. Decision No. 69663 modified the collection of transmission costs in retail rates to tie to the costs found in the FERC approved Open Access Transmission Tariff.

RATE

The charge shall be applied as follows:

Customer Class	TCA Charge
Residential	\$0.000000/kWh
General Service 20 kW or less	\$0.000000/kWh
General Service over 20 kW, under 3,000 kW	\$0.000/kW
General Service 3,000 kW and over	\$0.000/kW

Attachment C

TCA Rate Calculation - Plan of Administration

Line	Service Type Retail Transmission Rates	Residential \$/kWh (A)	GS≤20 kW \$/kWh (B)	GS > 20 kW and < 3MW \$/kW (C)	GS≥3 MW \$/kW (D)
1.	NITS (A)	0.000000	0.000000	0.000	0.000
2.	Scheduling (B)	0.000000	0.000000	0.000	0.000
3.	Regulation & Frequency (B)	0.000000	0.000000	0.000	0.000
4.	Spinning Reserve (B)	0.000000	0.000000	0.000	0.000
5.	Operating Reserve (B)	0.000000	0.000000	0.000	0.000
6.	Energy Imbalance (B)	0.000000	0.000000	0.000	0.000
7.	Total (Lines 1 thru 7)	0.000000	0.000000	0.000	0.000
8.	Included In Retail Base Rates (C)	0.000000	0.000000	0.000	0.000
9.	Balancing Account (D)	0.000000	0.000000	0.000	0.000
10.	TCA (Line 7 - Line 8 + Line 9) (E)	0.000000	0.000000	0.000	0.000

- (A) Source: Attachment H, Appendix A of Attachment H-1, Lines 161-164 - (APS's FERC Formula Rate Annual Update of transmission service rates pursuant to the APS OATT)
- (B) Source: Ancillary Services as defined in Schedule 11 of the APS OATT
- (C) Source: Base Transmission Rates as approved in Decision No. XXXXX
- (D) Source: TCA Balancing Account Workpaper Detail (to be provided with TCA filing)
- (E) Amounts presented in Attachment A and Attachment B

Average kWh per Month		
Base Rates	\$	%
PSA	\$	-
TCA	\$	-
RES	\$	-
DSMAC	\$	-
EIS	\$	-
SBA-2	\$	-
Four Corners	\$	-
LFCR	\$	-
Total	\$	-
	\$	0.00%
	\$	0.00%

ARIZONA PUBLIC SERVICE COMPANY
 Bill Impact of TCA Reset June 20XX

Attachment D

AVERAGE MONTHLY BILL IMPACTS				SEASONAL BILL IMPACTS			
Current		Proposed		Current		Proposed	
Average Monthly Bill ¹	Average Monthly Bill ²	\$ Impact	% Impact	Summer Monthly Bill	Winter Monthly Bill	Summer Monthly Bill	Winter Monthly Bill
Commercial - S (E-32)							
Average kWh per Month	-	-	-	-	-	-	-
Base Rates	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
PSA	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
TCA	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -	\$ -
RES	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
DSMAC	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
EIS	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
SBA-2	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
Four Corners	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
LFCR	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -	\$ -
Total	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -	\$ -
Commercial - M (E-32)							
Average kWh per Month	-	-	-	-	-	-	-
Base Rates	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
PSA	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
TCA	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -	\$ -
RES	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
DSMAC	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
EIS	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
SBA-2	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
Four Corners	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
LFCR	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -	\$ -
Total	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -	\$ -
Commercial - L (E-32)							
Average kWh per Month	-	-	-	-	-	-	-
Base Rates	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
PSA	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
TCA	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -	\$ -
RES	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
DSMAC	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
EIS	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
SBA-2	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
Four Corners	\$ -	\$ -	-	\$ -	\$ -	\$ -	\$ -
LFCR	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -	\$ -
Total	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -	\$ -

Attachment D

ARIZONA PUBLIC SERVICE COMPANY
Bill Impact of TCA Reset June 20XX

	AVERAGE MONTHLY BILL IMPACTS			SEASONAL BILL IMPACTS		
	Current	Proposed		Current	Proposed	
	Average Monthly Bill ¹	Average Monthly Bill ²	\$ Impact	Summer Monthly Bill	Summer Monthly Bill	Winter Monthly Bill
Industrial - XL (E-34.35)			% Impact			
Average kWh per Month	-	-	-	-	-	-
Base Rates	\$ -	\$ -	-	\$ -	\$ -	\$ -
PSA	\$ -	\$ -	-	\$ -	\$ -	\$ -
TCA	\$ -	\$ -	-	\$ -	\$ -	\$ -
RES	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -
DSMAC	\$ -	\$ -	-	\$ -	\$ -	\$ -
EIS	\$ -	\$ -	-	\$ -	\$ -	\$ -
SBA-2	\$ -	\$ -	-	\$ -	\$ -	\$ -
Four Corners	\$ -	\$ -	-	\$ -	\$ -	\$ -
LFGR	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -
Total	\$ -	\$ -	0.00%	\$ -	\$ -	\$ -

Notes:

- (1) Bill excludes regulatory assessment charge, taxes and fees. All Adjustor levels in effect as of May 15, 20XX.
- (2) Bill includes the projected impact to customers of the reset TCA adjustor.

Attachment E

Class Coincident Peak Demand

Class	20XX		20XX	
	MW	% of Coincident Demand	MW	% of Coincident Demand
Residential	0000.0	0.00%	0000.0	0.00%
General Service < 3MW	0000.0	0.00%	0000.0	0.00%
General Service > 3 MW	0000.0	0.00%	0000.0	0.00%
Total	0000.0	0.00%	0000.0	0.00%

Attachment F

Transmission Rates Embedded in Base Rates and TCA

Customer Group	Embedded Base Rate (A)	Current TCA Rate (B)	Proposed TCA Rate (C)	Difference (D) = (C) - (B)	Percentage Difference	
					TCA Rate (E) = (D)/(B)	Total (F) = (D)/[(A)+(B)]
Residential						
General Service 20 kW or less	\$ 0.000000 /kWh	\$ 0.000000 /kWh	\$ 0.000000 /kWh	\$ 0.000000 /kWh	0.0%	0.0%
General Service over 20 kW and under 3,000 kW	\$ 0.000000 /kWh	\$ 0.000000 /kWh	\$ 0.000000 /kWh	\$ 0.000000 /kWh	0.0%	0.0%
General Service 3,000 kW and over	\$ 0.0000 /kW	\$ 0.0000 /kW	\$ 0.0000 /kW	\$ 0.0000 /kW	0.0%	0.0%

ATTACHMENT G

Arizona Public Service Company
20XX Transmission Actual Addition Dollars and O&M

Line No.	Funding Project	W&A#	Description	Actual Cost	Purpose	Miles	Estimated O&M	In-Service Date
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
				Work Orders > \$250K	-			
				Work Orders < \$250K	-			
				Total	-			\$

ATTACHMENT G
Arizona Public Service Company
20XX Transmission Estimated Addition Dollars and O&M

Line #	Funding Project	WAA#	Description	Total Estimate	Purpose	Miles	Estimated O&M	Estimated In-Service Date
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
							\$	

Work Orders > \$250k

Work Orders < \$250K

Total \$

Arizona Public Service Company
20XX Transmission Estimated Addition Dollars and Q&M

ATTACHMENT G

Line #	Funding Project	WAA#	Description	Total Estimate	Purpose	Miles	Estimated O&M	Estimated In-Service Data
1								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
Work Orders > \$250k				-				
Work Orders < \$250k				-				
Total \$				-				\$

Attachment H

Arizona Public Service Company		FERC Form 1 Page # or Instruction		YEAR
Formula Rate -- Appendix A		Notes		
Shaded cells are input cells				
Wages & Salary Allocation Factor				
1	Transmission Wages Expense	p354.21.b		0
2	Total Wages Expense	p354.28b		0
3	Less A&G Wages Expense	p354.27b		0
4	Total	(Line 2 - 3)		0
5	Wages & Salary Allocator	(Line 1 / 4)		0.0000%
Plant Allocation Factors				
6	Electric Plant in Service	(Note 13)	Attachment 5	0
7	Total Plant in Service	(Sum Line 6)		0
8	Accumulated Depreciation (Total Electric Plant)		Attachment 5	0
9	Total Accumulated Depreciation	(Line 8)		0
10	Net Plant	(Line 7 - 9)		0
11	Transmission Gross Plant	(Line 22 - Line 38)		0
12	Gross Plant Allocator	(Line 11 / 7)		0.0000%
13	Transmission Net Plant	(Line 32 - Line 38)		0
14	Net Plant Allocator	(Line 13 / 10)		0.0000%
Plant in Service (Note O)				
15	Transmission Plant in Service	(Note 13)	Attachment 5	0
16	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)		Attachment 6	0
17	Total Transmission Plant in Service	(Line 15 + 16)		0
18	General & Intangible		Attachment 5	0
19	Total General	(Line 18)		0
20	Wage & Salary Allocation Factor	(Line 5)		0.0000%
21	General Plant Allocated to Transmission	(19 * 20)		0
22	TOTAL Plant in Service	(Line 17 + 21)		0
Accumulated Depreciation				
23	Transmission Accumulated Depreciation	(Note 13)	Attachment 5	0
24	Accumulated Depreciation for Transmission Plant Additions for Current Rate Year		Attachment 6	0
25	Total Transmission Accumulated Depreciation	(Line 23 + Line 24)		0
26	Accumulated General Depreciation		Attachment 5	0
27	Accumulated Intangible Depreciation		Attachment 5	0
28	Total Accumulated Depreciation	(Sum Lines 26 to 27)		0
29	Wage & Salary Allocation Factor	(Line 5)		0.0000%
30	General Allocated to Transmission	(Line 28 * 29)		0
31	TOTAL Accumulated Depreciation	(Line 25 + 30)		0
32	TOTAL Net Property, Plant & Equipment	(Line 22 - 31)		0

Adjustment To Rate Base

Attachment H

33	Accumulated Deferred Income Taxes			
	ADIT net of FASB 106 and 109	Attachment 1		0
34	Accumulated Deferred Income Taxes Allocated To Transmission	(Line 33)		0
35	Transmission O&M Reserves			
	Total Balance Transmission Related Account 242 Reserves	Enter Negative	Attachment 5	0
36	Prepayments	(Note A)	Attachment 5	0
37	Total Prepayments Allocated to Transmission	(Line 36)		0
38	Land Held for Future Use	(Note C)	p214	0
39	Materials and Supplies			
	Undistributed Stores Exp	(Note A)	p227 5c & 16 c	0
40	Wage & Salary Allocation Factor	(Line 5)		0.0000%
41	Total Transmission Allocated	(Line 39 * 40)		0
42	Transmission Materials & Supplies	p227 8c		0
43	Total Materials & Supplies Allocated to Transmission	(Line 41 + 42)		0
44	Cash Working Capital			
	Operation & Maintenance Expense	(Line 72)		0
45	Zero Cash Working Capital	Zero		0.0%
46	Total Cash Working Capital Allocated to Transmission	(Line 44 * 45)		0
47	Network Credits	(Note N)	Attachment 5	0
	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	Attachment 5	0
49	Net Outstanding Credits	(Line 47 - 48)		0
50	TOTAL Adjustment to Rate Base	(Line 34 + 35 + 37 + 38 + 43 + 46 - 49)		0
51	Rate Base	(Line 32 + 50)		0

O&M

52	Transmission O&M			
	Transmission O&M	p321 112 b		0
53	Less Account 565	p321 96 b		0
54	Transmission O&M	(Line 52 - 53)		0
55	Allocated General Expenses			
	Total A&G	p323 197 b		0
56	Less PBOP Adjustment	Attachment 5		0
57	Less Property Insurance Account 924	p323 185b		0
58	Less Regulatory Commission Exp Account 928	p323 189b		0
59	Less General Advertising Exp Account 930 1	p323 191b		0
60	Less EPRI Dues	p352-353		0
61	General Expenses	(Line 55) - Sum (56 to 60)		0
62	Wage & Salary Allocation Factor	(Line 5)		0.0000%
63	General Expenses Allocated to Transmission	(Line 61 * 62)		0
64	Directly Assigned A&G			
	Regulatory Commission Exp Account 928	(Note G)	Attachment 5	0
65	General Advertising Exp Account 930 1	(Note K)	Attachment 5	0
66	Subtotal - Transmission Related	(Line 64 + 65)		0
67	Property Insurance Account 924	p323 185b		0
68	General Advertising Exp Account 930 1	(Note I)	Attachment 5	0
69	Total	(Line 67 + 68)		0
70	Net Plant Allocation Factor	(Line 14)		0.0000%
71	A&G Directly Assigned to Transmission	(Line 69 * 70)		0
72	Total Transmission O&M	(Line 54 + 63 + 66 + 71)		0

Depreciation & Amortization Expense

73	Depreciation Expense (Note P)			
	Transmission Depreciation Expense	p336 7f		0
74	New plant Depreciation Expense	Attachment 6		0
75	Total Transmission Depreciation Expense	(Line 73 + Line 74)		0
76	General Depreciation	p336 10f		0
77	Intangible Amortization	(Note A)	p336 1f	0
78	Total	(Line 76 + 77)		0
79	Wage & Salary Allocation Factor	(Line 5)		0.0000%
80	General Depreciation Allocated to Transmission	(Line 78 * 79)		0
81	Total Transmission Depreciation & Amortization	(Line 75 + 80)		0

Attachment H

Taxes Other than Income				
82	Taxes Other than Income	Attachment 2		0
83	Total Taxes Other than Income	(Line 82)		0
Capitalization Calculations				
Long Term Interest				
84	Long Term Interest	p117.62c through 67c		0
85	Long Term Interest	(Line 84)		0
86	Preferred Dividends	enter positive	p118.29c	0
Common Stock				
87	Proprietary Capital		p112.16c	0
88	Less Preferred Stock	enter negative	(Line 96)	0
89	Less Accumulated Other Comprehensive Income Account 219	enter negative	p112.15c	0
90	Less Account 216.1	enter negative	p112.12c	0
91	Common Stock		(Sum Lines 87 to 90)	0
Capitalization				
92	Long Term Debt		p112.18c through 23c	0
93	Less Loss on Recquired Debt	enter negative	p111.81c	0
94	Plus Gain on Recquired Debt	enter positive	p113.61c	0
95	Total Long Term Debt		(Sum Lines 92 to 94)	0
96	Preferred Stock		p112.3c	0
97	Common Stock		(Line 91)	0
98	Total Capitalization		(Sum Lines 95 to 97)	0
99	Debt %		(Line 95 / 98)	0%
100	Preferred %		(Line 96 / 98)	0%
101	Common %		(Line 97 / 98)	0%
102	Debt Cost		(Line 85 / 95)	0.0000
103	Preferred Cost		(Line 86 / 96)	0.0000
104	Common Cost	(Note J)	Fixed	0.1075
105	Weighted Cost of Debt		(Line 99 * 102)	0.0000
106	Weighted Cost of Preferred		(Line 100 * 103)	0.0000
107	Weighted Cost of Common		(Line 101 * 104)	0.0000
108	Total Return (R)		(Sum Lines 105 to 107)	0.0000
109	Investment Return = Rate Base * Rate of Return		(Line 51 * 108)	0
Income Taxes				
Income Tax Rates				
110	FIT=Federal Income Tax Rate			0.00%
111	SIT=State Income Tax Rate or Composite	(Note I)		0.00%
112	p		FIT deductible for SIT	0.00%
113	$T = 1 - ((1 - SIT) * (1 - FIT)) / (1 - SIT * FIT * p)$			0.00%
114	T / (1-T)			0.00%
ITC Adjustment				
115	Amortized Investment Tax Credit	(Note I)	p266.8f	0
116	T/(1-T)	enter negative	(Line 114)	0.00%
117	Net Plant Allocation Factor		(Line 14)	0.0000%
118	ITC Adjustment Allocated to Transmission		(Line 115 * (1 - 116) * 117)	0
119	Income Tax Component =		(Line 114 * 109 * (1 - (105 / 108)))	-
120	Total Income Taxes		(Line 118 + 119)	-
REVENUE REQUIREMENT				
Summary				
121	Net Property, Plant & Equipment		(Line 32)	0
122	Adjustment to Rate Base		(Line 50)	0
123	Rate Base		(Line 51)	0
124	O&M		(Line 72)	0
125	Depreciation & Amortization		(Line 81)	0
126	Taxes Other than Income		(Line 83)	0
127	Investment Return		(Line 109)	0
128	Income Taxes		(Line 120)	0
129	Gross Revenue Requirement		(Sum Lines 124 to 128)	0

Attachment H

Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
130	Transmission Plant In Service	(Line 15)	0
131	Excluded Transmission Facilities	(Note M) Attachment 5	0
132	Included Transmission Facilities	(Line 130 - 131)	0
133	Inclusion Ratio	(Line 132 / 130)	0.00%
134	Gross Revenue Requirement	(Line 129)	0
135	Adjusted Gross Revenue Requirement	(Line 133 * 134)	0
Revenue Credits & Interest on Network Credits			
136	Revenue Credits	Attachment 3	0
137	Interest on Network Credits	(Note N) Attachment 5	0
138	Net Revenue Requirement	(Line 135 - 136 + 137)	0
Net Plant Carrying Charge			
139	Net Revenue Requirement	(Line 138)	-
140	Net Transmission Plant	(Line 15 - 23)	-
141	Net Plant Carrying Charge	(Line 139 / 140)	0.0000%
142	Net Plant Carrying Charge without Depreciation	(Line 139 - 73) / 140	0.0000%
143	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	(Line 139 - 73 - 109 - 120) / 140	0.0000%
Net Plant Carrying Charge Calculation per 100 Basis Point Increase in ROE			
144	Net Revenue Requirement Less Return and Taxes	(Line 138 - 127 - 128)	-
145	Increased Return and Taxes	Attachment 4	-
146	Net Revenue Requirement per 100 Basis Point increase in ROE	(Line 144 - 145)	-
147	Net Transmission Plant	(Line 15 - 23)	-
148	Net Plant Carrying Charge per 100 Basis Point increase in ROE	(Line 146 / 147)	0.0000%
149	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	(Line 146 - 73) / 147	0.0000%
Net Revenue Requirement			
150	Net Revenue Requirement	(Line 138)	-
151	True-up amount	Attachment 6	-
152	Plus any increased ROE calculated on Attachment 7	Attachment 7	-
153	Facility Credits under Section 30.9 of the APS OATT	Attachment 5	-
154	Net Adjusted Revenue Requirement	(Line 150 - 151 + 153)	-
Annual Point-to-Point Transmission Rate			
155	Average of the 4 Summer CP	(Note L) Network Transmission Peak Report	0
156	Annual Point-to-Point Transmission Rate	(Line 154 / 155)	0.00
157	Average of the 8 Non-Summer CP	(Note L) Network Transmission Peak Report	0
158	Implied Non-Summer Revenue Requirement	((Line 156/12)*8* Line 157)	0
159	Implied Summer Revenue Requirement	(Line 138 - Line 158)	0
160	Implied Annualized Summer Point-to-Point Transmission Rate	((Line 154 - line 158/Line 155/4)*12)	0.00
Retail Transmission Rates			
161	Residential (kWh)	Rate Design Worksheet	0.00000
162	Gen Serv < 3MW Without Demand Meters - Includes All Customers 20 kW and less (kWh)	Rate Design Worksheet	0.00000
163	Gen Serv < 3MW (kW)	Rate Design Worksheet	0.000
164	Gen Serv > 3MW (kW)	Rate Design Worksheet	0.000

Notes

- A Electric portion only
- B Exclude Construction Work In Progress expensed as O&M (rather than amortized). New Transmission plant that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in the Transmission Plan must be separately detailed on Attachment 5
- For the Reconciliation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service
- C Transmission Portion Only
- D All EPRI Annual Membership Dues
- E All Regulatory Commission Expenses
- F Safety related advertising included in Account 930.1
- G Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h
- I The currently effective income tax rate, where FIT is the Federal income tax rate, SIT is the State income tax rate, and $p = \frac{\text{the percentage of federal income tax deductible for state income taxes}}{\text{the percentage of federal income tax deductible for state income taxes}}$. If the utility includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8 f) multiplied by (1/(1-T)). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income. If the tax rates change during a calendar year, an average tax rate will be used - calculated based on the number of days each was effective in the calendar year
- J ROE of 10.75%
- K Education and outreach expenses relating to transmission, for example siting or billing
- L Based on APS Network Transmission Peak Report
- M Amount of transmission plant excluded from rates per Attachment 5
- N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmission Owner whole on Line 137
- O AFUDC shall not be applied to the portion of a Network Upgrade for which the customer has provided the funds.
- P Changes in depreciation or amortization rates must be filed with the Commission, as well as any new depreciation or amortization rates

Instructions for Account 190

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewers or Production) are directly assigned to Column C.
2. ADIT items related only to Transmission are directly assigned to Column D.
3. ADIT items related only to Transmission are directly assigned to Column D.
4. ADIT items related to Plant and not in Columns C & D are included in Column E.
5. ADIT items related to labor and not in Columns C & D are included in Column F.
6. Deferred income taxes area when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the form, the associated ADIT amount shall be excluded.
7. Form 1-6 filer: Sum of subtotals for Accounts 382 and 383 should tie to Form No. 1-6, p. 113.57 c.

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

ADIT-282	A						G
	Total	B	C	D	E	F	
			Gas, Prod Or Other	Only Transmission Related	Plant Related	Labor Related	Justification
Subtotal - e275 (Form 1-F filer: see note 6 below)							
Less FASB 109 Above if not separately removed						0	
Less FASB 106 Above if not separately removed							
Total						0	

Instructions for Account 282:

- ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C.
- ADIT items related only to Transmission are directly assigned to Column D.
- ADIT items related to Plant and not in Columns C & D are included in Column E.
- ADIT items related to labor and not in Columns C & D are included in Column F.
- Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.
- Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should be to Form No. 1-F, p.113.57 c.

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

ADIT-283	A						G
	Total	B	C	D	E	F	
			Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	Justification
Subtotal - e277 (Form 1-F filer: see note 6 below)							
Less FASB 109 Above if not separately removed							
Less FASB 106 Above if not separately removed							
Total							

Instructions for Account 283:

- ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C.
- ADIT items related only to Transmission are directly assigned to Column D.
- ADIT items related to Plant and not in Columns C & D are included in Column E.
- ADIT items related to labor and not in Columns C & D are included in Column F.
- Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.
- Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should be to Form No. 1-F, p.113.57 c.

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

ADITC-255

		Balance	Amortization
1	Rate Base Treatment Balance to Attachment 1, Page 1, Transmission Related ADIT 255.		
2			
3	Amortization		
4	Amortization to line 115 of Appendix A		
5	Total		
6	Total Form No. 1 (p 206 & 267)		
7	Difference /1		

One or the other but not both

/1 Difference must be zero

Arizona Public Service Company
Attachment 2 - Taxes Other Than Income Worksheet

Other Taxes	Page 263 Col (i)	Allocator	Allocated Amount
Plant Related		Gross Plant Allocator	
1 Transmission Personal Property Tax (directly assigned to Transmission)	100%	\$	-
2 Capital Stock Tax	0.0000%	\$	-
3 Gross Premium (insurance) Tax	0.0000%	\$	-
4 PURTA	0.0000%	\$	-
5 Corp License	0.0000%	\$	-
Total Plant Related	0	\$	0
Labor Related		Wages & Salary Allocator	
6 Federal FICA & Unemployment & state unemployment			
Total Labor Related	0	0.0000%	0
Other Included		Gross Plant Allocator	
7 Miscellaneous	0		
Total Other Included	0	0.0000%	0
Total Included			0
Currently Excluded			
8 Use & Sales Tax	0		
9 Adjust state and local tax reserve			
10 Other Sales & Use Tax	0		
11 Other Personal Property Tax (excluded)			
12			
13			
14			
15			
16			
17			
18			
20			
21 Total "Other" Taxes (included on p. 263)	<u>0</u>		
22 Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	<u> </u>		
23 Difference			

Criteria for Allocation:

- A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Gross Plant Allocator: If the taxes are 100% recovered at retail they will not be included
- B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator: If the taxes are 100% recovered at retail they will not be included
- C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator
- D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Gross Plant Allocator; provided, however, that overheads shall be treated as in footnote B above
- E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Arizona Public Service Company

Attachment 3 - Revenue Credit Workpaper

Account 454 - Rent from Electric Property

- 1 Rent from Electric Property - Transmission Related (Note 3) -
- 2 Total Rent Revenues (Sum Lines 1) -

Account 456 - Other Electric Revenues (Note 1)

- 3 Scheduling, System Control & Dispatch (Ancillary Service) p398 line 1 column g
- 4 Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (Note 4) -
- 5 Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4) -
- 6 Transitional Revenue Neutrality (Note 1) -
- 7 Transitional Market Expansion (Note 1) -
- 8 Professional Services (Note 3) -
- 9 Revenues from Directly Assigned Transmission Facility Charges (Note 2) -
- 10 Rent or Attachment Fees associated with Transmission Facilities (Note 3) -
- 11 Gross Revenue Credits (Sum Lines 2-10) -
- 12 Line 17g -
- 13 Total Revenue Credits -

Revenue Adjustment to determine Revenue Credit

- 14 Note 1: All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 171 of Appendix A.
- 15 Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.
- 16 Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).
- 17a Revenues included in lines 1-11 which are subject to 50/50 sharing. -
- 17b Costs associated with revenues in line 17a -
- 17c Net Revenues (17a - 17b) -
- 17d 50% Share of Net Revenues (17c / 2) -
- 17e Costs associated with revenues in line 17a that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue -
- 17f Net Revenue Credit (17d + 17e) -
- 17g Line 17f less line 17a -
- 18 Note 4: If the facilities associated with the revenues are not included in the formula, the revenue is shown here but not included in the total above and is explained in the Cost Support, for example revenues associated with distribution facilities. -
- 19 Amount offset in line 4 above
- 20 Total Account 454 and 456 -

Composite Tax Rate

0.00%

Arizona Public Service Company

Attachment 4 - Calculation of 100 Basis Point Increase in ROE

A	100 Basis Point increase in ROE and Income Taxes	Line 12 + Line 23	-
B	100 Basis Point increase in ROE		1.00%

Return Calculation			
1	Rate Base	Appendix A, Line 51	-
2	Debt %	Appendix A, Line 99	0.0%
3	Preferred %	Appendix A, Line 100	0.0%
4	Common %	Appendix A, Line 101	0.0%
5	Debt Cost	Appendix A, Line 102	0.00%
6	Preferred Cost	Appendix A, Line 103	0.00%
7	Common Cost	Appendix A % plus 100 Basis Pts	11.75%
8	Weighted Cost of Debt	Appendix A, Line 105	-
9	Weighted Cost of Preferred	Appendix A, Line 106	-
10	Weighted Cost of Common	Line 4 * Line 7	0.0000
11	Total Return (R)	Sum Lines 8 to 10	0.0000
12	Investment Return = Rate Base * Rate of Return	Line 11 * Line 1	0

Composite Income Taxes			
Income Tax Rates			
13	FIT=Federal Income Tax Rate	Appendix A, Line 110	0.00%
14	SIT=State Income Tax Rate or Composite	Appendix A, Line 111	0.00%
15	p (percent of federal income tax deductible for state purposes)	Appendix A, Line 112	0.00%
16	$T = 1 - \frac{[(1 - SIT) * (1 - FIT)]}{(1 - SIT * FIT * p)}$	Appendix A, Line 113	0.00%
17	$T / (1 - T)$	Appendix A, Line 114	0.00%
ITC Adjustment			
18	Amortized Investment Tax Credit	Appendix A, Line 115	-
19	$1/(1 - T)$	Appendix A, Line 116	0.0000%
20	Net Plant Allocation Factor	Appendix A, Line 117	0.0000%
21	ITC Adjustment Allocated to Transmission	Appendix A, Line 118	0
22	Income Tax Component = CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	Line 17*Line 12*(1-(Line 8/Line 11))	-
23	Total Income Taxes	Line 21 + 22"	-

Arizona Public Service Company
Attachment 5 - Cost Support

Plant In Service Worksheet		Account & Line Description	Page # and Instructions	Balance For True up	Balance for Estimate
Calculation of Transmission Plant In Service					
December	Source	2013			
January	p206 38 b	2014			
February	company records	2014			
March	company records	2014			
April	company records	2014			
May	company records	2014			
June	company records	2014			
July	company records	2014			
August	company records	2014			
September	company records	2014			
October	company records	2014			
November	company records	2014			
December	p207 58 g	2014			
Transmission Plant In Service					
Calculation of Distribution Plant In Service					
December	Source	2013			
January	p206 75 b	2014			
February	company records	2014			
March	company records	2014			
April	company records	2014			
May	company records	2014			
June	company records	2014			
July	company records	2014			
August	company records	2014			
September	company records	2014			
October	company records	2014			
November	company records	2014			
December	p207 75 g	2014			
Distribution Plant In Service					
Calculation of Intangible Plant In Service					
December	Source	2013			
December	p204 5 b	2014			
Intangible Plant In Service					
Calculation of General Plant In Service					
December	Source	2013			
December	p206 96 b	2014			
General Plant In Service					
Calculation of Production Plant In Service					
December	Source	2013			
January	p204 46b	2014			
February	company records	2014			
March	company records	2014			
April	company records	2014			
May	company records	2014			
June	company records	2014			
July	company records	2014			
August	company records	2014			
September	company records	2014			
October	company records	2014			
November	company records	2014			
December	company records	2014			
Production Plant In Service					
Total Plant In Service					
		Sum of averages above		0	0

Accumulated Depreciation Worksheet				Attachment A Line 16, Descriptions, Notes, Form 1 Page 8e and Instructions		Balance For True up		Details	
Calculation of Transmission Accumulated Depreciation				Source		2013		Balance for Estimate	
December				Prior year p219 25		2013			
January				company records		2014			
February				company records		2014			
March				company records		2014			
April				company records		2014			
May				company records		2014			
June				company records		2014			
July				company records		2014			
August				company records		2014			
September				company records		2014			
October				company records		2014			
November				company records		2014			
December				p219 25		2014			
Transmission Accumulated Depreciation									
Calculation of Distribution Accumulated Depreciation				Source		2013			
December				Prior year p219 26		2013			
January				company records		2014			
February				company records		2014			
March				company records		2014			
April				company records		2014			
May				company records		2014			
June				company records		2014			
July				company records		2014			
August				company records		2014			
September				company records		2014			
October				company records		2014			
November				company records		2014			
December				p219 26		2014			
Distribution Accumulated Depreciation									
Calculation of Intangible Accumulated Depreciation				Source		2013			
December				Prior year p200 21 c		2013			
December				p200 21 c		2014			
Accumulated Intangible Depreciation									
Calculation of General Accumulated Depreciation				Source		2013			
December				Prior year p219 28		2013			
December				p219 28		2014			
Accumulated General Depreciation									
Calculation of Production Accumulated Depreciation				Source		2013			
December				Prior year p219 20 thru 219 24		2013			
January				company records		2014			
February				company records		2014			
March				company records		2014			
April				company records		2014			
May				company records		2014			
June				company records		2014			
July				company records		2014			
August				company records		2014			
September				company records		2014			
October				company records		2014			
November				company records		2014			
December				p219 20 thru 219 24		2014			
Production Accumulated Depreciation									
Total Accumulated Depreciation				Sum of averages above		0		0	

Prepayments		Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Bag of year	End of Year	End of Year for Est. Average for Final	Allocation	Yrns Related	Details
38	Prepayments		Worksheet 5	-	-	-	0.000%	-	-
	Labor Related		Worksheet 5	-	-	-	0.000%	-	-
	Plant Related		Worksheet 5	-	-	-	100.000%	-	-
	100% Transmission Related		Worksheet 5	-	-	-	0.000%	-	-
	Other (Excluded)		Worksheet 5	-	-	-	0.000%	-	-
Materials & Supplies									
		Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Bag of year	End of Year	End of Year for Est. Average for Final			Details
39	Stores Expense Undistributed		p227.16	-	-	-			
42	Transmission Materials & Supplies		p227.8	-	-	-			
Outstanding Network Credits Cost Support									
		Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Bag of year	End of Year	End of Year for Est. Average for Final			Description of the Credits
Network Credits									
47	Outstanding Network Credits		Account 252	-	-	-			General Description of the Credits
	December		2013						
	December		Account 252						
	Average Beginning and End of Year		2014						
48	Accumulated Depreciation Associated with Facilities with Outstanding Network Credits		Account 252	-	-	-			General Description of the Credits
	December		2013						
	December		Account 252						
	Average Beginning and End of Year		2014						
Interest on Outstanding Network Credits Cost Support									
		Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Bag of year	End of Year	End of Year for Est. Average for Final			Description of the Interest on the Credits
137	Interest on Network Credits			-	-	-			

Arizona Public Service Company
Attachment 6 - Estimate and Reconciliation Worksheet

- Exec Summary**
- | Step | Month | Year | Action |
|------|-------|--------|--|
| 1 | April | Year 2 | TO populate the formula with Year 1 data from FERC Form 1 |
| 2 | April | Year 2 | TO estimate all transmission Cap Adds, Retirements, and associated depreciation for Year 2 based on Months expected to be in service in Year 2. |
| 3 | April | Year 2 | TO add estimates from Step 2 to Appendix A |
| 4 | May | Year 2 | Post results of Step 3 on APS web site. |
| 5 | June | Year 2 | Results of Step 3 go into effect. |
| 6 | April | Year 3 | TO populate the formula with Year 2 data from FERC Form 1. |
| 7 | April | Year 3 | Reconciliation - TO calculates the true up amount by subtracting the results of Step 6 by Step 3. |
| 8 | April | Year 3 | Reconciliation - TO calculates interest and amortization associated with the true up calculated in Step 7 and applies that amount to line 151 of the formula. |
| 9 | April | Year 3 | TO estimate all transmission Cap Adds, Retirements, CWIP and associated depreciation for Year 3 based on Months expected to be in service and monthly CWIP balances in Year 3. |
| 10 | April | Year 3 | TO add 13 month average Cap Adds and retirements (line 16 and 24) to the Formula |
| 11 | May | Year 3 | Post results of Step 10 on APS web site. |
| 12 | June | Year 3 | Results of Step 9 go into effect for the Rate Year 2. |

Reconciliation details

1

April

Year 2

TO populate the formula with Year 1 data from FERC Form 1
Rev Req based on Year 1 data

2

April

Year 2

TO estimate all transmission Cap Adds, Retirements, and associated depreciation for Year 2 based on Months expected to be in service in Year 2

Must run Appendix A to get this number (without estimated cap adds) from Appendix A

(A)	(B)	(C)	(D)	(E)	(F)	(G)
Other Project PIS	other retirements	Project X PIS	Project X PIS retirements	Other Project PIS	Accumulated Balance	Total
					Project X PIS	Project X PIS
Dec			0	0	0	0
Jan			0	0	0	0
Feb			0	0	0	0
Mar			0	0	0	0
Apr			0	0	0	0
May			0	0	0	0
Jun			0	0	0	0
Jul			0	0	0	0
Aug			0	0	0	0
Sep			0	0	0	0
Oct			0	0	0	0
Nov			0	0	0	0
Dec			0	0	0	0
Total						

13 month avg of new plant additions = Col F + Col H

goes to line 16 of the formula

(I) = F Total Other Project PIS		(J) Composite Trans Deprec Rate	(K) = I * J Depreciation Expense	(L) Accum Deprec	(M) = H Total Project X PIS	(N) Composite Trans Deprec Rate	(O) = L * M Depreciation Expense	(P) Accum Deprec
Jan	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Feb	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Mar	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Apr	0	0.00%	0.00%	-	-	0.00%	0.00%	-
May	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Jun	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Jul	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Aug	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Sep	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Oct	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Nov	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Dec	0	0.00%	0.00%	-	-	0.00%	0.00%	-
Total			13 mo. Avg accumulated depreciation = Col L * Col P Depreciation Expense = Col K + Col O	-	-	0.00%	0.00%	-

goes to line 24 of the formula
goes to line 74 of the formula

- 3 April Year 2 TO add estimates from Step 2 to Appendix A
Include inputs to Appendix A Lines 16, 24, and 74
- 4 May Year 2 Post results of Step 3 on APS web site
Must run Appendix A to get this number (with results of step 2)
- 5 June Year 2 Results of Step 3 go into effect.
- 6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1
Rev Req based on Prior Year data
step 6 file
- 7 April Year 3 Reconciliation - TO calculates the true up amount by subtracting the results of Step 6 by Step 3.
Prior Year True Up First Year True up
Total True Up

True Up to be recovered \$
Divide True up w/o interest by the number of months the rate was in effect and place that result in the month that the rate went in effect in the interest calculation below

6	April	Year 3	Reconciliation: 1-Q calculates interest and amortization associated with the true up calculated in Step 7 and applies that amount to line 151 of the formula Interest on Amount of Refunds or Surpluses									
			Interest 35 19a for 1st quarter Current Yr									
			Month	Yr	1/12 of Step 7	Interest 35 19a for and 35 19 b March Current Yr	Months	Interest	Refunds Owed			
			Jun	Year 1	-	0.00%	11.5	-	-			
			Jul	Year 1	-	0.00%	10.5	-	-			
			Aug	Year 1	-	0.00%	9.5	-	-			
			Sep	Year 1	-	0.00%	8.5	-	-			
			Oct	Year 1	-	0.00%	7.5	-	-			
			Nov	Year 1	-	0.00%	6.5	-	-			
			Dec	Year 1	-	0.00%	5.5	-	-			
			Jan	Year 2	-	0.00%	4.5	-	-			
			Feb	Year 2	-	0.00%	3.5	-	-			
			Mar	Year 2	-	0.00%	2.5	-	-			
			Apr	Year 2	-	0.00%	1.5	-	-			
			May	Year 2	-	0.00%	0.5	-	-			
			Total									
			Jun	Year 2		Balance	Interest	Amort	Balance			
			Jul	Year 2			0.00%					
			Aug	Year 2			0.00%					
			Sep	Year 2			0.00%					
			Oct	Year 2			0.00%					
			Nov	Year 2			0.00%					
			Dec	Year 2			0.00%					
			Jan	Year 3			0.00%					
			Feb	Year 3			0.00%					
			Mar	Year 3			0.00%					
			Apr	Year 3			0.00%					
			May	Year 3			0.00%					
			Total with interest				0.00%					

The difference between the Reconciliation in Step 6 and the forecast in Prior Year with interest

9 April Year 3 TO estimates all transmission Cap Adds, Retirements, CWIP and associated depreciation for Year 3 based on Months expected to be in service and monthly CWP balances in Year 3.
Note: Jan and Feb are actuals, Mar-Dec forecasted. Retirements are not forecasted

	(A) Other Project PIS		(B) other retirements		(C) Project X PIS		(D) Project X PIS retirements		(E) Other Project PIS		(F) Accumulated Balance		(G) Total	
	Other Project PIS	other retirements	Project X PIS	Project X PIS retirements	Other Project PIS	Project X PIS	Project X PIS retirements	Other Project PIS	Project X PIS	Project X PIS	Project X PIS	Project X PIS	Project X PIS	Project X PIS
Dec														
Jan														
Feb														
Mar														
Apr														
May														
Jun														
Jul														
Aug														
Sep														
Oct														
Nov														
Dec														
Total														

13 month avg of new plant additions = Col F + Col H

goes to line 16 of the formula

	(I) = F		(J) Composite Trans		(K) = I * J		(L) Accum Deprec		(M) = H		(N) Composite Trans		(O) = L * M		(P) Accum	
	Total Other Project PIS	Deprec Rate	Deprec Rate	Deprec Rate	Deprec Rate	Deprec Rate	Deprec Rate	Deprec Rate	Total Project X PIS	Deprec Rate	Deprec Rate	Deprec Rate	Deprec Rate	Deprec Rate	Deprec Rate	Deprec Rate
Jan																
Feb																
Mar																
Apr																
May																
Jun																
Jul																
Aug																
Sep																
Oct																
Nov																
Dec																
Total																

13 mo. Avg accumulated depreciation = Col L + Col P
Depreciation Expense = Col K + Col O

goes to line 24 of the formula
goes to line 74 of the formula

10 April Year 3 TO adds 13 month average Cap Adds and retirements (line 110 and 120) to the Formula
Rev Req based on Year 2 data with estimated Cap Adds, Ret, and Deprec for Year 3 Cap Adds (Step 9) and True up of Year 1 data (Step 8)
Must run App A to get this # (with 13 mo. avg cap adds, depreciation for Year 3 cap adds)

11 May Year 3 Post results of Step 10 on APS web site.

12 June Year 3 Results of Step 9 go into effect for the Rate Year 2.
Step 11 plus the difference between the Reconciliation in Step 6 and the forecast in Prior Year with interest

Arizona Public Service Company
Attachment 7 - Transmission Enhancement Charge Worksheet

Line #	Formula/Line	Project A	Project B	Rev Credit
1	152	Plus any increased ROE calculated on Attachment 7		
2	Fixed Charge Rate (FCR) if not a CIAC			
3	A	Net Plant Carrying Charge without Depreciation		
4	B	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation		
5	C	Line B less Line A		
6	FCR if a CIAC			
7	D	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		
The FCR resulting from Formula in a given year is used for that year only				
Therefore actual revenues collected in a year do not change based on cost data for subsequent years				
Beginning = 13 month Plant CWIP or Incentive Plant balance				
Deprec = 13 month avg Accumulated Depreciation				
Ending = Beginning - Deprec				
Revenue = FCR* Ending + Ending				
Total = Sum of Revenue for Project CWP and PS				
Incentive = Total for "W Increased ROE" row				
Revenue Credit = Total for "FCR W base ROE" row				
6	Life	No	No	
7	CIAC	0	0	
8	Increased ROE (Basis Points)	0.000%	0.000%	
9	FCR W base ROE	0.000%	0.000%	
10	FCR W increased ROE	0.000%	0.000%	
11	Investment			
12	Annual Depreciation Exp			
13	13 monthly Avg			
14	Invest Yr			
15	FCR W base ROE			
16	W increased ROE			
17	FCR W base ROE			
18	W increased ROE			
19	FCR W base ROE			
20	W increased ROE			
21	FCR W base ROE			
22	W increased ROE			
23	FCR W base ROE			
24	W increased ROE			
25	FCR W base ROE			
26	W increased ROE			
27	FCR W base ROE			
28	W increased ROE			
29	FCR W base ROE			
30	W increased ROE			
31	FCR W base ROE			
32	W increased ROE			
33	FCR W base ROE			
34	W increased ROE			
35	FCR W base ROE			
36	W increased ROE			
37	FCR W base ROE			
38	W increased ROE			
39	FCR W base ROE			
40	W increased ROE			
41	FCR W base ROE			
42	W increased ROE			
43	FCR W base ROE			
44	W increased ROE			
45	FCR W base ROE			
46	W increased ROE			
47	FCR W base ROE			
48	W increased ROE			
49	FCR W base ROE			
50	W increased ROE			
51	FCR W base ROE			
52	W increased ROE			
53	FCR W base ROE			
54	W increased ROE			
55				
56				

Arizona Public Service Company

Attachment 8 - Depreciation Rates

Plant Account	Depreciation Rates
352.01 - Structures	1.84%
353 - Station Equipment	2.14%
354 - Towers and Fixtures	1.34%
355.01 - Poles and Fixtures - Wood	2.21%
355.02 - Poles and Fixtures - Steel	2.10%
356 - Overhead Conductors and Devices	1.87%
357 - Underground Conduit	1.55%
358 - Underground Conductors and Devices	1.33%

Appendix R

RULE-BASED COMPLIANCE REQUIREMENTS ELIMINATED OR WAIVED

Rule	Topic	Frequency	Description
R14-2-1613(A)	Retail Competition	Annual	Report on competitive services and standard offer services provided by Electric Service Providers and Affected Utilities
R14-2-1617	Retail Competition	Annual	Provide a Consumer Disclosure Label containing price, fuel mix, and emissions data for the prior year
R14-2-2308	Net Metering	Annual	Provide the inverter or generator rating, monthly energy deliveries and if available the monthly peak demand for each net metering facility

DECISION-BASED COMPLIANCE REQUIREMENTS ELIMINATED OR WAIVED

Decision	Docket	Topic	Frequency	Description
Redundant Filings				
70531 Page 22, line 1 (09/30/08)	E-01345A-08-0106	RES	Annual	Report any damage payments received related to the Solana PPA contract
72058 Page 10, line 25 (01/06/11)	E-01345A-10-0314	RES	Annual	Report any damage payments received related to the Perrin Ranch PPA contract
71275 Page 15, line 4 (9/17/09)	E-01345A-09-0263	RES	Annual	Report production from systems installed as a result of the 2009 school UFI program and do not report "phantom" production
71244 Page 8, line 13 (08/06/09)	E-01345A-09-0255	Rates	Annual	Report detailing transmission projects and O&M costs included in each Transmission Cost Adjustor reset and expected future TCA costs
Outdated Filings				
68112 Page 7, line 3 (09/09/05)	E-01345A-03-0775 E-01345A-04-0657	Bill Estimation	Non-dated	Participate in benchmarking studies that compare APS estimation and other billing practices to other utilities

Decision	Docket	Topic	Frequency	Description
68645 Page 9, line 3 (04/12/06)	E-01345A-05-0674	Rates	Annual	Provide load shape data for participants served under experimental rates ET-2 and ECT-2
69569 Page 8, line 8 (05/21/07)	E-01345A-05-0711	Bill Estimation	Non-dated	Update allocation data for summer/winter on-peak usage, load factor, and usage per day when change is more than 5%
71448 Page 61, line 12 (12/30/09)	E-01345A-08-0172	Rate Case	As necessary	Notify Commission prior to replacing full-time employees with off-shored employees
71448 Page 61, line 26 (12/30/09)	E-01345A-08-0172	Rate Case	Annual	Develop a Carbon Credit Tracking Mechanism
71958 Page 6, line 26 (11/01/10)	E-01345A-10-0013	RES	Annual	Notify Commission if the Bagdad REC and Energy project has precluded any other commercial system from receiving incentives
72022 Page 29, line 1 (12/10/10)	E-01345A-10-0166 E-01345A-10-0262	RES	Annual	Summarize RES reports (Compliance Report and Implementation Plans) with 1-2 page summaries and a PowerPoint presentation
72022 Page 28, line 22 (12/10/10)	E-01345A-10-0166 E-01345A-10-0262	RES	Annual	Disclose if affiliates, employees, or directors have financial or other interest in renewable energy projects
72582 Page 14, line 22 (09/15/11)	E-01345A-10-0123	Technology Innovation	Annual	Report on the development of the EV market in APS territory
73089 (04/05/12) Page 62, line 1	E-01345A-11-0232	DSM/EE	Annual	Present an overview of the DSM Annual Progress Report at an Open Meeting
73089 (04/05/12) Page 61, line 6	E-01345A-11-0232	DSM/EE	Annual	Report spending associated with non-energy efficiency measures in the Appliance Recycling program
73089 (04/05/12) Page 61, line 11	E-01345A-11-0232	DSM/EE	Annual	Provide information on how savings from the Bid for Efficiency pilot measure are verified

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-XS



(excludes bill reduction from transferring adjutor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
0-100	18.24	21.54	3.31	18.1%
101-200	27.92	33.21	5.29	18.9%
201-300	37.61	44.89	7.28	19.3%
301-400	47.30	56.56	9.26	19.6%
401-500	61.12	68.23	7.12	11.6%
501-600	74.93	79.90	4.97	6.6%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
0-100	16.27	19.44	3.17	19.5%
101-200	23.99	29.01	5.02	20.9%
201-300	31.72	38.58	6.87	21.7%
301-400	39.44	48.15	8.72	22.1%
401-500	47.16	57.73	10.57	22.4%
501-600	54.88	67.30	12.41	22.6%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-XS

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
0-100	26.94	21.54	(5.39)	-20.0%
101-200	37.92	33.21	(4.70)	-12.4%
201-300	49.38	44.89	(4.50)	-9.1%
301-400	60.73	56.56	(4.17)	-6.9%
401-500	71.83	68.23	(3.60)	-5.0%
501-600	82.82	79.90	(2.92)	-3.5%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
0-100	24.11	19.44	(4.67)	-19.4%
101-200	31.63	29.01	(2.62)	-8.3%
201-300	38.61	38.58	(0.03)	-0.1%
301-400	43.44	48.15	4.71	10.8%
401-500	48.09	57.73	9.63	20.0%
501-600	52.92	67.30	14.37	27.2%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-XS

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
0-100	27.39	21.54	(5.85)	-21.3%
101-200	38.10	33.21	(4.88)	-12.8%
201-300	48.80	44.89	(3.92)	-8.0%
301-400	59.51	56.56	(2.95)	-5.0%
401-500	70.22	68.23	(1.99)	-2.8%
501-600	80.93	79.90	(1.02)	-1.3%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
0-100	23.48	19.44	(4.04)	-17.2%
101-200	30.28	29.01	(1.27)	-4.2%
201-300	37.08	38.58	1.50	4.1%
301-400	43.88	48.15	4.27	9.7%
401-500	50.82	57.73	6.91	13.6%
501-600	57.62	67.30	9.68	16.8%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-XS

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
0-100	34.26	21.54	(12.71)	-37.1%
101-200	51.57	33.21	(18.36)	-35.6%
201-300	69.48	44.89	(24.59)	-35.4%
301-400	75.08	56.56	(18.53)	-24.7%
401-500	86.08	68.23	(17.85)	-20.7%
501-600	99.66	79.90	(19.76)	-19.8%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
0-100	26.98	19.44	(7.54)	-28.0%
101-200	38.23	29.01	(9.21)	-24.1%
201-300	48.48	38.58	(9.90)	-20.4%
301-400	52.25	48.15	(4.10)	-7.8%
401-500	58.78	57.73	(1.05)	-1.8%
501-600	67.20	67.30	0.10	0.1%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-XS

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
0-100	34.36	21.54	(12.82)	-37.3%
101-200	52.04	33.21	(18.83)	-36.2%
201-300	69.72	44.89	(24.83)	-35.6%
301-400	75.25	56.56	(18.69)	-24.8%
401-500	86.18	68.23	(17.95)	-20.8%
501-600	99.81	79.90	(19.91)	-19.9%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
0-100	26.77	19.44	(7.33)	-27.4%
101-200	37.79	29.01	(8.78)	-23.2%
201-300	47.88	38.58	(9.30)	-19.4%
301-400	51.46	48.15	(3.31)	-6.4%
401-500	57.85	57.73	(0.13)	-0.2%
501-600	66.08	67.30	1.21	1.8%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-Basic

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	\$ 88.75	101.54	12.79	14.4%
701-800	\$ 102.57	113.93	11.37	11.1%
801-900	\$ 118.73	126.33	7.59	6.4%
901-1000	\$ 134.90	138.72	3.82	2.8%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	\$ 51.40	71.18	19.78	38.5%
701-800	\$ 57.52	79.23	21.72	37.8%
801-900	\$ 63.64	87.29	23.65	37.2%
901-1000	\$ 63.17	86.67	23.50	37.2%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charge
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-Basic

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	94.04	101.54	7.50	8.0%
701-800	105.15	113.93	8.79	8.4%
801-900	116.25	126.33	10.08	8.7%
901-1000	127.11	138.72	11.61	9.1%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	56.25	71.18	14.93	26.5%
701-800	61.93	79.23	17.31	27.9%
801-900	67.43	87.29	19.86	29.5%
901-1000	67.06	86.67	19.61	29.2%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-Basic

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	91.63	101.54	9.91	10.8%
701-800	102.34	113.93	11.59	11.3%
801-900	113.05	126.33	13.28	11.7%
901-1000	123.76	138.72	14.96	12.1%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	54.53	71.18	16.65	30.5%
701-800	59.88	79.23	19.35	32.3%
801-900	65.37	87.29	21.92	33.5%
901-1000	64.92	86.67	21.75	33.5%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-Basic

(excludes bill reduction from transferring adjustor rates to base rates)

	(A)	(B)	(C)	(D)
Summer			Change	
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount (\$) (B) - (A)	% (C) / (A)
kWh block				
601-700	115.89	101.54	(14.35)	-12.4%
701-800	120.46	113.93	(6.52)	-5.4%
801-900	132.97	126.33	(6.65)	-5.0%
901-1000	144.20	138.72	(5.48)	-3.8%

	(A)	(B)	(C)	(D)
Winter			Change	
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount (\$) (B) - (A)	% (C) / (A)
kWh block				
601-700	65.10	71.18	6.08	9.3%
701-800	67.73	79.23	11.51	17.0%
801-900	73.76	87.29	13.53	18.3%
901-1000	72.39	86.67	14.28	19.7%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-Basic

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	114.79	101.54	(13.25)	-12%
701-800	120.32	113.93	(6.38)	-5%
801-900	132.60	126.33	(6.27)	-5%
901-1000	143.53	138.72	(4.80)	-3%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	63.53	71.18	7.64	12%
701-800	66.37	79.23	12.87	19%
801-900	72.01	87.29	15.28	21%
901-1000	70.86	86.67	15.81	22%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-Basic L

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
1001-1100	\$ 151.07	167.27	16.21	10.7%
1101-1200	\$ 167.23	180.68	13.45	8.0%
1201-1300	\$ 183.40	194.10	10.70	5.8%
1301-1400	\$ 199.57	207.51	7.94	4.0%
1401-1500	\$ 215.74	220.92	5.19	2.4%
1501-1600	\$ 231.90	234.33	2.43	1.0%
1601-1700	\$ 248.07	247.74	(0.32)	-0.1%
1701-1800	\$ 264.24	261.16	(3.08)	-1.2%
1801-1900	\$ 280.40	274.57	(5.83)	-2.1%
1901-2000	\$ 296.57	287.98	(8.59)	-2.9%
2001-2500	\$ 377.41	355.04	(22.36)	-5.9%
2501-3000	\$ 458.24	422.10	(36.14)	-7.9%
3001-4000	\$ 630.81	556.22	(74.59)	-11.8%
4001-5000	\$ 803.38	690.34	(113.04)	-14.1%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
1001-1100	\$ 68.63	105.31	36.68	53.4%
1101-1200	\$ 74.09	113.09	39.00	52.6%
1201-1300	\$ 79.55	120.87	41.31	51.9%
1301-1400	\$ 85.02	128.65	43.63	51.3%
1401-1500	\$ 90.48	136.42	45.95	50.8%
1501-1600	\$ 95.94	144.20	48.26	50.3%
1601-1700	\$ 101.40	151.98	50.58	49.9%
1701-1800	\$ 113.64	169.42	55.77	49.1%
1801-1900	\$ 119.48	177.73	58.25	48.8%
1901-2000	\$ 125.32	186.05	60.73	48.5%
2001-2500	\$ 154.51	227.63	73.11	47.3%
2501-3000	\$ 183.71	269.20	85.50	46.5%
3001-4000	\$ 242.09	352.36	110.27	45.5%
4001-5000	\$ 300.48	435.51	135.04	44.9%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-Basic L

(excludes bill reduction from transferring adjustor rates to base rates)

	(A)	(B)	(C)	(D)
Summer			Change	
kWh block	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount (\$) (B) - (A)	% (C) / (A)
1001-1100	139.43	167.27	27.85	20.0%
1101-1200	149.68	180.68	31.00	20.7%
1201-1300	160.42	194.10	33.67	21.0%
1301-1400	170.43	207.51	37.07	21.8%
1401-1500	181.05	220.92	39.87	22.0%
1501-1600	191.43	234.33	42.90	22.4%
1601-1700	202.17	247.74	45.57	22.5%
1701-1800	212.91	261.16	48.25	22.7%
1801-1900	222.68	274.57	51.89	23.3%
1901-2000	233.42	287.98	54.56	23.4%
2001-2500	285.18	355.04	69.86	24.5%
2501-3000	342.64	422.10	79.46	23.2%
3001-4000	441.55	556.22	114.67	26.0%
4001-5000	550.89	690.34	139.45	25.3%

	(A)	(B)	(C)	(D)
Winter			Change	
kWh block	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount (\$) (B) - (A)	% (C) / (A)
1001-1100	71.81	105.31	33.50	46.7%
1101-1200	78.35	113.09	34.73	44.3%
1201-1300	83.10	120.87	37.76	45.4%
1301-1400	87.76	128.65	40.88	46.6%
1401-1500	92.87	136.42	43.55	46.9%
1501-1600	97.71	144.20	46.49	47.6%
1601-1700	102.82	151.98	49.16	47.8%
1701-1800	114.09	169.42	55.33	48.5%
1801-1900	118.88	177.73	58.85	49.5%
1901-2000	124.75	186.05	61.29	49.1%
2001-2500	151.14	227.63	76.48	50.6%
2501-3000	179.33	269.20	89.87	50.1%
3001-4000	227.98	352.36	124.37	54.6%
4001-5000	282.02	435.51	153.49	54.4%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-Basic L

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
1001-1100	134.47	167.27	32.81	24.4%
1101-1200	145.17	180.68	35.51	24.5%
1201-1300	155.88	194.10	38.22	24.5%
1301-1400	166.59	207.51	40.92	24.6%
1401-1500	177.30	220.92	43.62	24.6%
1501-1600	188.00	234.33	46.33	24.6%
1601-1700	198.71	247.74	49.03	24.7%
1701-1800	209.42	261.16	51.74	24.7%
1801-1900	220.13	274.57	54.44	24.7%
1901-2000	230.84	287.98	57.15	24.8%
2001-2500	284.37	355.04	70.67	24.8%
2501-3000	337.91	422.10	84.19	24.9%
3001-4000	444.99	556.22	111.23	25.0%
4001-5000	552.07	690.34	138.27	25.0%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
1001-1100	77.67	105.31	27.64	35.6%
1101-1200	83.14	113.09	29.95	36.0%
1201-1300	88.75	120.87	32.12	36.2%
1301-1400	94.22	128.65	34.43	36.5%
1401-1500	99.82	136.42	36.60	36.7%
1501-1600	105.29	144.20	38.91	37.0%
1601-1700	110.90	151.98	41.08	37.0%
1701-1800	123.24	169.42	46.17	37.5%
1801-1900	129.23	177.73	48.50	37.5%
1901-2000	135.08	186.05	50.96	37.7%
2001-2500	164.75	227.63	62.87	38.2%
2501-3000	194.29	269.20	74.92	38.6%
3001-4000	253.49	352.36	98.87	39.0%
4001-5000	312.69	435.51	122.82	39.3%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charge
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-Basic L

(excludes bill reduction from transferring adjustor rates to base rates)

	(A)	(B)	(C)	(D)
Summer			Change	
kWh block	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount (\$) (B) - (A)	% (C) / (A)
1001-1100	156.00	167.27	11.28	7.2%
1101-1200	168.32	180.68	12.37	7.3%
1201-1300	180.50	194.10	13.59	7.5%
1301-1400	189.72	207.51	17.78	9.4%
1401-1500	201.88	220.92	19.04	9.4%
1501-1600	214.00	234.33	20.33	9.5%
1601-1700	215.06	247.74	32.68	15.2%
1701-1800	216.12	261.16	45.04	20.8%
1801-1900	227.12	274.57	47.45	20.9%
1901-2000	231.01	287.98	56.97	24.7%
2001-2500	284.76	355.04	70.28	24.7%
2501-3000	319.58	422.10	102.52	32.1%
3001-4000	420.25	556.22	135.97	32.4%
4001-5000	496.70	690.34	193.64	39.0%

	(A)	(B)	(C)	(D)
Winter			Change	
kWh block	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount (\$) (B) - (A)	% (C) / (A)
1001-1100	77.77	105.31	27.54	35.4%
1101-1200	83.09	113.09	30.00	36.1%
1201-1300	87.66	120.87	33.21	37.9%
1301-1400	92.05	128.65	36.60	39.8%
1401-1500	97.49	136.42	38.93	39.9%
1501-1600	102.95	144.20	41.25	40.1%
1601-1700	103.60	151.98	48.38	46.7%
1701-1800	111.29	169.42	58.13	52.2%
1801-1900	116.13	177.73	61.60	53.0%
1901-2000	117.97	186.05	68.08	57.7%
2001-2500	144.27	227.63	83.35	57.8%
2501-3000	161.09	269.20	108.11	67.1%
3001-4000	209.17	352.36	143.19	68.5%
4001-5000	246.39	435.51	189.12	76.8%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-Basic L

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
1001-1100	155.80	167.27	11.47	7%
1101-1200	168.08	180.68	12.60	7%
1201-1300	180.36	194.10	13.73	8%
1301-1400	189.94	207.51	17.57	9%
1401-1500	202.22	220.92	18.70	9%
1501-1600	214.50	234.33	19.83	9%
1601-1700	215.98	247.74	31.76	15%
1701-1800	217.46	261.16	43.70	20%
1801-1900	228.39	274.57	46.18	20%
1901-2000	232.57	287.98	55.41	24%
2001-2500	287.22	355.04	67.82	24%
2501-3000	321.62	422.10	100.49	31%
3001-4000	422.81	556.22	133.41	32%
4001-5000	498.36	690.34	191.99	39%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
1001-1100	77.13	105.31	28.18	37%
1101-1200	82.53	113.09	30.56	37%
1201-1300	87.02	120.87	33.85	39%
1301-1400	91.49	128.65	37.16	41%
1401-1500	96.91	136.42	39.52	41%
1501-1600	102.31	144.20	41.90	41%
1601-1700	103.08	151.98	48.91	47%
1701-1800	110.80	169.42	58.62	53%
1801-1900	115.47	177.73	62.26	54%
1901-2000	117.33	186.05	68.72	59%
2001-2500	143.43	227.63	84.19	59%
2501-3000	160.22	269.20	108.99	68%
3001-4000	207.75	352.36	144.61	70%
4001-5000	244.13	435.51	191.39	78%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charge
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to TOU-E

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	\$ 88.75	106.80	18.05	20.3%
701-800	\$ 102.57	120.22	17.66	17.2%
801-900	\$ 118.73	133.65	14.92	12.6%
901-1000	\$ 134.90	147.08	12.18	9.0%
1001-1100	\$ 151.07	160.50	9.44	6.2%
1101-1200	\$ 167.23	173.93	6.70	4.0%
1201-1300	\$ 183.40	187.36	3.96	2.2%
1301-1400	\$ 199.57	200.79	1.22	0.6%
1401-1500	\$ 215.74	214.21	(1.52)	-0.7%
1501-1600	\$ 231.90	227.64	(4.26)	-1.8%
1601-1700	\$ 248.07	241.07	(7.00)	-2.8%
1701-1800	\$ 264.24	254.49	(9.74)	-3.7%
1801-1900	\$ 280.40	267.92	(12.48)	-4.5%
1901-2000	\$ 296.57	281.35	(15.22)	-5.1%
2001-2500	\$ 377.41	348.48	(28.93)	-7.7%
2501-3000	\$ 458.24	415.61	(42.63)	-9.3%
3001-4000	\$ 630.81	549.88	(80.93)	-12.8%
4001-5000	\$ 803.38	684.15	(119.23)	-14.8%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	\$ 51.40	62.86	11.46	22.3%
701-800	\$ 57.52	69.97	12.45	21.6%
801-900	\$ 63.64	77.21	13.57	21.3%
901-1000	\$ 63.17	76.56	13.39	21.2%
1001-1100	\$ 68.63	83.14	14.51	21.1%
1101-1200	\$ 74.09	89.39	15.30	20.7%
1201-1300	\$ 79.55	95.65	16.09	20.2%
1301-1400	\$ 85.02	102.23	17.22	20.3%
1401-1500	\$ 90.48	108.48	18.01	19.9%
1501-1600	\$ 95.94	114.96	19.02	19.8%
1601-1700	\$ 101.40	121.32	19.92	19.6%
1701-1800	\$ 113.64	135.67	22.02	19.4%
1801-1900	\$ 119.48	142.46	22.98	19.2%
1901-2000	\$ 125.32	149.26	23.94	19.1%
2001-2500	\$ 154.51	183.45	28.94	18.7%
2501-3000	\$ 183.71	217.54	33.83	18.4%
3001-4000	\$ 242.09	285.71	43.62	18.0%
4001-5000	\$ 300.48	353.99	53.51	17.8%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to TOU-E

(excludes bill reduction from transferring adjustor rates to base rates)

	(A)	(B)	(C)	(D)
Summer	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	94.04	106.80	12.76	13.6%
701-800	105.15	120.22	15.08	14.3%
801-900	116.25	133.65	17.40	15.0%
901-1000	127.11	147.08	19.97	15.7%
1001-1100	139.43	160.50	21.08	15.1%
1101-1200	149.68	173.93	24.25	16.2%
1201-1300	160.42	187.36	26.94	16.8%
1301-1400	170.43	200.79	30.35	17.8%
1401-1500	181.05	214.21	33.16	18.3%
1501-1600	191.43	227.64	36.21	18.9%
1601-1700	202.17	241.07	38.90	19.2%
1701-1800	212.91	254.49	41.58	19.5%
1801-1900	222.68	267.92	45.24	20.3%
1901-2000	233.42	281.35	47.93	20.5%
2001-2500	285.18	348.48	63.30	22.2%
2501-3000	342.64	415.61	72.98	21.3%
3001-4000	441.55	549.88	108.33	24.5%
4001-5000	550.89	684.15	133.26	24.2%

	(A)	(B)	(C)	(D)
Winter	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	56.25	62.86	6.61	11.8%
701-800	61.93	69.97	8.04	13.0%
801-900	67.43	77.21	9.78	14.5%
901-1000	67.06	76.56	9.50	14.2%
1001-1100	71.81	83.14	11.34	15.8%
1101-1200	78.35	89.39	11.04	14.1%
1201-1300	83.10	95.65	12.54	15.1%
1301-1400	87.76	102.23	14.47	16.5%
1401-1500	92.87	108.48	15.61	16.8%
1501-1600	97.71	114.96	17.25	17.7%
1601-1700	102.82	121.32	18.50	18.0%
1701-1800	114.09	135.67	21.58	18.9%
1801-1900	118.88	142.46	23.58	19.8%
1901-2000	124.75	149.26	24.51	19.6%
2001-2500	151.14	183.45	32.31	21.4%
2501-3000	179.33	217.54	38.21	21.3%
3001-4000	227.98	285.71	57.73	25.3%
4001-5000	282.02	353.99	71.97	25.5%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to TOU-E

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	91.63	106.80	15.16	16.5%
701-800	102.34	120.22	17.88	17.5%
801-900	113.05	133.65	20.60	18.2%
901-1000	123.76	147.08	23.32	18.8%
1001-1100	134.47	160.50	26.04	19.4%
1101-1200	145.17	173.93	28.76	19.8%
1201-1300	155.88	187.36	31.48	20.2%
1301-1400	166.59	200.79	34.20	20.5%
1401-1500	177.30	214.21	36.92	20.8%
1501-1600	188.00	227.64	39.63	21.1%
1601-1700	198.71	241.07	42.35	21.3%
1701-1800	209.42	254.49	45.07	21.5%
1801-1900	220.13	267.92	47.79	21.7%
1901-2000	230.84	281.35	50.51	21.9%
2001-2500	284.37	348.48	64.11	22.5%
2501-3000	337.91	415.61	77.70	23.0%
3001-4000	444.99	549.88	104.89	23.6%
4001-5000	552.07	684.15	132.08	23.9%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	54.53	62.86	8.33	15.3%
701-800	59.88	69.97	10.09	16.9%
801-900	65.37	77.21	11.84	18.1%
901-1000	64.92	76.56	11.63	17.9%
1001-1100	77.67	83.14	5.47	7.0%
1101-1200	83.14	89.39	6.26	7.5%
1201-1300	88.75	95.65	6.90	7.8%
1301-1400	94.22	102.23	8.02	8.5%
1401-1500	99.82	108.48	8.66	8.7%
1501-1600	105.29	114.96	9.67	9.2%
1601-1700	110.90	121.32	10.42	9.4%
1701-1800	123.24	135.67	12.42	10.1%
1801-1900	129.23	142.46	13.23	10.2%
1901-2000	135.08	149.26	14.18	10.5%
2001-2500	164.75	183.45	18.70	11.3%
2501-3000	194.29	217.54	23.25	12.0%
3001-4000	253.49	285.71	32.22	12.7%
4001-5000	312.69	353.99	41.30	13.2%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to TOU-E

(excludes bill reduction from transferring adjutor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under	Monthly Bill under	Change	
	Current Rates	Proposed Rates	Amount (\$)	%
kWh block			(B) - (A)	(C) / (A)
601-700	115.89	106.80	(9.09)	-7.8%
701-800	120.46	120.22	(0.23)	-0.2%
801-900	132.97	133.65	0.68	0.5%
901-1000	144.20	147.08	2.88	2.0%
1001-1100	156.00	160.50	4.51	2.9%
1101-1200	168.32	173.93	5.62	3.3%
1201-1300	180.50	187.36	6.85	3.8%
1301-1400	189.72	200.79	11.06	5.8%
1401-1500	201.88	214.21	12.33	6.1%
1501-1600	214.00	227.64	13.63	6.4%
1601-1700	215.06	241.07	26.00	12.1%
1701-1800	216.12	254.49	38.37	17.8%
1801-1900	227.12	267.92	40.80	18.0%
1901-2000	231.01	281.35	50.33	21.8%
2001-2500	284.76	348.48	63.72	22.4%
2501-3000	319.58	415.61	96.03	30.0%
3001-4000	420.25	549.88	129.63	30.8%
4001-5000	496.70	684.15	187.45	37.7%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under	Monthly Bill under	Change	
	Current Rates	Proposed Rates	Amount (\$)	%
kWh block			(B) - (A)	(C) / (A)
601-700	65.10	62.86	(2.24)	-3.4%
701-800	67.73	69.97	2.24	3.3%
801-900	73.76	77.21	3.45	4.7%
901-1000	72.39	76.56	4.16	5.8%
1001-1100	77.77	83.14	5.37	6.9%
1101-1200	83.09	89.39	6.31	7.6%
1201-1300	87.66	95.65	7.99	9.1%
1301-1400	92.05	102.23	10.18	11.1%
1401-1500	97.49	108.48	10.99	11.3%
1501-1600	102.95	114.96	12.01	11.7%
1601-1700	103.60	121.32	17.72	17.1%
1701-1800	111.29	135.67	24.38	21.9%
1801-1900	116.13	142.46	26.34	22.7%
1901-2000	117.97	149.26	31.29	26.5%
2001-2500	144.27	183.45	39.18	27.2%
2501-3000	161.09	217.54	56.45	35.0%
3001-4000	209.17	285.71	76.54	36.6%
4001-5000	246.39	353.99	107.60	43.7%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charge
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to TOU-E

(excludes bill reduction from transferring adjustor rates to base rates)

Summer	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	114.79	106.80	(7.99)	-7%
701-800	120.32	120.22	(0.09)	0%
801-900	132.60	133.65	1.06	1%
901-1000	143.53	147.08	3.55	2%
1001-1100	155.80	160.50	4.70	3%
1101-1200	168.08	173.93	5.85	3%
1201-1300	180.36	187.36	6.99	4%
1301-1400	189.94	200.79	10.84	6%
1401-1500	202.22	214.21	11.99	6%
1501-1600	214.50	227.64	13.14	6%
1601-1700	215.98	241.07	25.08	12%
1701-1800	217.46	254.49	37.03	17%
1801-1900	228.39	267.92	39.53	17%
1901-2000	232.57	281.35	48.78	21%
2001-2500	287.22	348.48	61.26	21%
2501-3000	321.62	415.61	94.00	29%
3001-4000	422.81	549.88	127.07	30%
4001-5000	498.36	684.15	185.79	37%

Winter	(A)	(B)	(C)	(D)
	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
kWh block			Amount (\$) (B) - (A)	% (C) / (A)
601-700	63.53	62.86	(0.67)	-1%
701-800	66.37	69.97	3.60	5%
801-900	72.01	77.21	5.20	7%
901-1000	70.86	76.56	5.70	8%
1001-1100	77.13	83.14	6.02	8%
1101-1200	82.53	89.39	6.87	8%
1201-1300	87.02	95.65	8.63	10%
1301-1400	91.49	102.23	10.74	12%
1401-1500	96.91	108.48	11.58	12%
1501-1600	102.31	114.96	12.66	12%
1601-1700	103.08	121.32	18.24	18%
1701-1800	110.80	135.67	24.87	22%
1801-1900	115.47	142.46	27.00	23%
1901-2000	117.33	149.26	31.93	27%
2001-2500	143.43	183.45	40.02	28%
2501-3000	160.22	217.54	57.32	36%
3001-4000	207.75	285.71	77.96	38%
4001-5000	244.13	353.99	109.86	45%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charge
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-2

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$)	%
				(B) - (A)	(C) / (A)
601-700	4.4	\$ 88.75	111.49	22.74	25.6%
701-800	4.4	\$ 102.57	120.30	17.74	17.3%
801-900	4.9	\$ 118.73	133.32	14.59	12.3%
901-1000	5.3	\$ 134.90	145.50	10.60	7.9%
1001-1100	5.8	\$ 151.07	158.51	7.45	4.9%
1101-1200	6.3	\$ 167.23	171.53	4.30	2.6%
1201-1300	6.8	\$ 183.40	184.55	1.15	0.6%
1301-1400	7.1	\$ 199.57	195.88	(3.68)	-1.8%
1401-1500	7.6	\$ 215.74	208.90	(6.83)	-3.2%
1501-1600	8.1	\$ 231.90	221.92	(9.98)	-4.3%
1601-1700	7.8	\$ 248.07	228.22	(19.85)	-8.0%
1701-1800	7.5	\$ 264.24	234.51	(29.72)	-11.2%
1801-1900	7.9	\$ 280.40	246.69	(33.71)	-12.0%
1901-2000	7.8	\$ 296.57	254.67	(41.90)	-14.1%
2001-2500	9.8	\$ 377.41	315.55	(61.86)	-16.4%
2501-3000	10.3	\$ 458.24	363.83	(94.41)	-20.6%
3001-4000	13.7	\$ 630.81	480.56	(150.25)	-23.8%
4001-5000	15.2	\$ 803.38	581.33	(222.05)	-27.6%

Winter		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$)	%
				(B) - (A)	(C) / (A)
601-700	2.9	\$ 51.40	74.78	23.38	45.5%
701-800	2.9	\$ 57.52	80.13	22.62	39.3%
801-900	3.2	\$ 63.64	88.04	24.41	38.3%
901-1000	3.1	\$ 63.17	86.78	23.61	37.4%
1001-1100	3.4	\$ 68.63	94.11	25.48	37.1%
1101-1200	3.7	\$ 74.09	101.42	27.32	36.9%
1201-1300	3.9	\$ 79.55	107.88	28.32	35.6%
1301-1400	4.1	\$ 85.02	114.37	29.35	34.5%
1401-1500	4.4	\$ 90.48	121.67	31.19	34.5%
1501-1600	4.7	\$ 95.94	129.00	33.06	34.5%
1601-1700	4.5	\$ 101.40	132.10	30.70	30.3%
1701-1800	4.7	\$ 113.64	144.53	30.89	27.2%
1801-1900	4.9	\$ 119.48	151.33	31.85	26.7%
1901-2000	4.8	\$ 125.32	155.62	30.30	24.2%
2001-2500	6.1	\$ 154.51	192.16	37.65	24.4%
2501-3000	6.4	\$ 183.71	220.30	36.60	19.9%
3001-4000	8.5	\$ 242.09	289.19	47.10	19.5%
4001-5000	9.4	\$ 300.48	347.99	47.52	15.8%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-2

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$) (B) - (A)	% (C) / (A)
601-700	4.4	94.04	111.49	17.45	18.6%
701-800	4.4	105.15	120.30	15.16	14.4%
801-900	4.9	116.25	133.32	17.07	14.7%
901-1000	5.3	127.11	145.50	18.39	14.5%
1001-1100	5.8	139.43	158.51	19.09	13.7%
1101-1200	6.3	149.68	171.53	21.85	14.6%
1201-1300	6.8	160.42	184.55	24.13	15.0%
1301-1400	7.1	170.43	195.88	25.45	14.9%
1401-1500	7.6	181.05	208.90	27.85	15.4%
1501-1600	8.1	191.43	221.92	30.49	15.9%
1601-1700	7.8	202.17	228.22	26.05	12.9%
1701-1800	7.5	212.91	234.51	21.60	10.1%
1801-1900	7.9	222.68	246.69	24.01	10.8%
1901-2000	7.8	233.42	254.67	21.25	9.1%
2001-2500	9.8	285.18	315.55	30.37	10.6%
2501-3000	10.3	342.64	363.83	21.19	6.2%
3001-4000	13.7	441.55	480.56	39.01	8.8%
4001-5000	15.2	550.89	581.33	30.44	5.5%

Winter		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$) (B) - (A)	% (C) / (A)
601-700	2.9	56.25	74.78	18.53	32.9%
701-800	2.9	61.93	80.13	18.21	29.4%
801-900	3.2	67.43	88.04	20.62	30.6%
901-1000	3.1	67.06	86.78	19.73	29.4%
1001-1100	3.4	71.81	94.11	22.31	31.1%
1101-1200	3.7	78.35	101.42	23.06	29.4%
1201-1300	3.9	83.10	107.88	24.77	29.8%
1301-1400	4.1	87.76	114.37	26.60	30.3%
1401-1500	4.4	92.87	121.67	28.79	31.0%
1501-1600	4.7	97.71	129.00	31.29	32.0%
1601-1700	4.5	102.82	132.10	29.28	28.5%
1701-1800	4.7	114.09	144.53	30.44	26.7%
1801-1900	4.9	118.88	151.33	32.45	27.3%
1901-2000	4.8	124.75	155.62	30.87	24.7%
2001-2500	6.1	151.14	192.16	41.02	27.1%
2501-3000	6.4	179.33	220.30	40.97	22.8%
3001-4000	8.5	227.98	289.19	61.21	26.8%
4001-5000	9.4	282.02	347.99	65.97	23.4%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-2

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$) (B) - (A)	% (C) / (A)
601-700	4.4	91.63	111.49	19.85	21.7%
701-800	4.4	102.34	120.30	17.96	17.6%
801-900	4.9	113.05	133.32	20.27	17.9%
901-1000	5.3	123.76	145.50	21.74	17.6%
1001-1100	5.8	134.47	158.51	24.05	17.9%
1101-1200	6.3	145.17	171.53	26.36	18.2%
1201-1300	6.8	155.88	184.55	28.67	18.4%
1301-1400	7.1	166.59	195.88	29.30	17.6%
1401-1500	7.6	177.30	208.90	31.61	17.8%
1501-1600	8.1	188.00	221.92	33.91	18.0%
1601-1700	7.8	198.71	228.22	29.50	14.8%
1701-1800	7.5	209.42	234.51	25.09	12.0%
1801-1900	7.9	220.13	246.69	26.56	12.1%
1901-2000	7.8	230.84	254.67	23.83	10.3%
2001-2500	9.8	284.37	315.55	31.18	11.0%
2501-3000	10.3	337.91	363.83	25.92	7.7%
3001-4000	13.7	444.99	480.56	35.57	8.0%
4001-5000	15.2	552.07	581.33	29.26	5.3%

Winter		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$) (B) - (A)	% (C) / (A)
601-700	2.9	54.53	74.78	20.24	37.1%
701-800	2.9	59.88	80.13	20.25	33.8%
801-900	3.2	65.37	88.04	22.68	34.7%
901-1000	3.1	64.92	86.78	21.86	33.7%
1001-1100	3.4	77.67	94.11	16.45	21.2%
1101-1200	3.7	83.14	101.42	18.28	22.0%
1201-1300	3.9	88.75	107.88	19.13	21.6%
1301-1400	4.1	94.22	114.37	20.15	21.4%
1401-1500	4.4	99.82	121.67	21.85	21.9%
1501-1600	4.7	105.29	129.00	23.71	22.5%
1601-1700	4.5	110.90	132.10	21.20	19.1%
1701-1800	4.7	123.24	144.53	21.29	17.3%
1801-1900	4.9	129.23	151.33	22.10	17.1%
1901-2000	4.8	135.08	155.62	20.53	15.2%
2001-2500	6.1	164.75	192.16	27.41	16.6%
2501-3000	6.4	194.29	220.30	26.02	13.4%
3001-4000	8.5	253.49	289.19	35.70	14.1%
4001-5000	9.4	312.69	347.99	35.30	11.3%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-2

(excludes bill reduction from transferring adjustor rates to base rates)

		(A)	(B)	(C)	(D)
Summer				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
				(B) - (A)	(C) / (A)
601-700	4.4	115.89	111.49	(4.40)	-3.8%
701-800	4.4	120.46	120.30	(0.15)	-0.1%
801-900	4.9	132.97	133.32	0.35	0.3%
901-1000	5.3	144.20	145.50	1.30	0.9%
1001-1100	5.8	156.00	158.51	2.52	1.6%
1101-1200	6.3	168.32	171.53	3.22	1.9%
1201-1300	6.8	180.50	184.55	4.04	2.2%
1301-1400	7.1	189.72	195.88	6.16	3.2%
1401-1500	7.6	201.88	208.90	7.02	3.5%
1501-1600	8.1	214.00	221.92	7.91	3.7%
1601-1700	7.8	215.06	228.22	13.15	6.1%
1701-1800	7.5	216.12	234.51	18.39	8.5%
1801-1900	7.9	227.12	246.69	19.57	8.6%
1901-2000	7.8	231.01	254.67	23.65	10.2%
2001-2500	9.8	284.76	315.55	30.79	10.8%
2501-3000	10.3	319.58	363.83	44.25	13.8%
3001-4000	13.7	420.25	480.56	60.31	14.4%
4001-5000	15.2	496.70	581.33	84.63	17.0%

		(A)	(B)	(C)	(D)
Winter				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
				(B) - (A)	(C) / (A)
601-700	2.9	65.10	74.78	9.68	14.9%
701-800	2.9	67.73	80.13	12.41	18.3%
801-900	3.2	73.76	88.04	14.29	19.4%
901-1000	3.1	72.39	86.78	14.39	19.9%
1001-1100	3.4	77.77	94.11	16.34	21.0%
1101-1200	3.7	83.09	101.42	18.33	22.1%
1201-1300	3.9	87.66	107.88	20.22	23.1%
1301-1400	4.1	92.05	114.37	22.32	24.2%
1401-1500	4.4	97.49	121.67	24.17	24.8%
1501-1600	4.7	102.95	129.00	26.05	25.3%
1601-1700	4.5	103.60	132.10	28.50	27.5%
1701-1800	4.7	111.29	144.53	33.24	29.9%
1801-1900	4.9	116.13	151.33	35.21	30.3%
1901-2000	4.8	117.97	155.62	37.65	31.9%
2001-2500	6.1	144.27	192.16	47.89	33.2%
2501-3000	6.4	161.09	220.30	59.21	36.8%
3001-4000	8.5	209.17	289.19	80.02	38.3%
4001-5000	9.4	246.39	347.99	101.61	41.2%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-2

(excludes bill reduction from transferring adjustor rates to base rates)

		(A)	(B)	(C)	(D)
Summer				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
				(B) - (A)	(C) / (A)
601-700	4.4	114.79	111.49	(3.30)	-2.9%
701-800	4.4	120.32	120.30	(0.01)	0.0%
801-900	4.9	132.60	133.32	0.73	0.5%
901-1000	5.3	143.53	145.50	1.97	1.4%
1001-1100	5.8	155.80	158.51	2.71	1.7%
1101-1200	6.3	168.08	171.53	3.45	2.1%
1201-1300	6.8	180.36	184.55	4.18	2.3%
1301-1400	7.1	189.94	195.88	5.94	3.1%
1401-1500	7.6	202.22	208.90	6.68	3.3%
1501-1600	8.1	214.50	221.92	7.42	3.5%
1601-1700	7.8	215.98	228.22	12.23	5.7%
1701-1800	7.5	217.46	234.51	17.05	7.8%
1801-1900	7.9	228.39	246.69	18.30	8.0%
1901-2000	7.8	232.57	254.67	22.10	9.5%
2001-2500	9.8	287.22	315.55	28.33	9.9%
2501-3000	10.3	321.62	363.83	42.22	13.1%
3001-4000	13.7	422.81	480.56	57.75	13.7%
4001-5000	15.2	498.36	581.33	82.97	16.6%

		(A)	(B)	(C)	(D)
Winter				Change	
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
				(B) - (A)	(C) / (A)
601-700	2.9	63.53	74.78	11.24	17.7%
701-800	2.9	66.37	80.13	13.77	20.7%
801-900	3.2	72.01	88.04	16.04	22.3%
901-1000	3.1	70.86	86.78	15.93	22.5%
1001-1100	3.4	77.13	94.11	16.99	22.0%
1101-1200	3.7	82.53	101.42	18.89	22.9%
1201-1300	3.9	87.02	107.88	20.86	24.0%
1301-1400	4.1	91.49	114.37	22.88	25.0%
1401-1500	4.4	96.91	121.67	24.76	25.6%
1501-1600	4.7	102.31	129.00	26.69	26.1%
1601-1700	4.5	103.08	132.10	29.03	28.2%
1701-1800	4.7	110.80	144.53	33.73	30.4%
1801-1900	4.9	115.47	151.33	35.87	31.1%
1901-2000	4.8	117.33	155.62	38.29	32.6%
2001-2500	6.1	143.43	192.16	48.73	34.0%
2501-3000	6.4	160.22	220.30	60.09	37.5%
3001-4000	8.5	207.75	289.19	81.44	39.2%
4001-5000	9.4	244.13	347.99	103.87	42.5%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$)	%
				(B) - (A)	(C) / (A)
601-700	4.4	\$ 88.75	130.74	41.99	47.3%
701-800	4.4	\$ 102.57	136.63	34.06	33.2%
801-900	4.9	\$ 118.73	151.23	32.50	27.4%
901-1000	5.3	\$ 134.90	164.09	29.19	21.6%
1001-1100	5.8	\$ 151.07	178.70	27.63	18.3%
1101-1200	6.3	\$ 167.23	193.30	26.07	15.6%
1201-1300	6.8	\$ 183.40	207.91	24.51	13.4%
1301-1400	7.1	\$ 199.57	219.02	19.46	9.7%
1401-1500	7.6	\$ 215.74	233.63	17.89	8.3%
1501-1600	8.1	\$ 231.90	248.23	16.33	7.0%
1601-1700	7.8	\$ 248.07	248.89	0.82	0.3%
1701-1800	7.5	\$ 264.24	249.54	(14.69)	-5.6%
1801-1900	7.9	\$ 280.40	262.41	(18.00)	-6.4%
1901-2000	7.8	\$ 296.57	266.55	(30.02)	-10.1%
2001-2500	9.8	\$ 377.41	330.85	(46.55)	-12.3%
2501-3000	10.3	\$ 458.24	369.00	(89.24)	-19.5%
3001-4000	13.7	\$ 630.81	487.15	(143.66)	-22.8%
4001-5000	15.2	\$ 803.38	572.17	(231.21)	-28.8%

Winter		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$)	%
				(B) - (A)	(C) / (A)
601-700	2.9	\$ 51.40	72.86	21.46	41.8%
701-800	2.9	\$ 57.52	76.36	18.84	32.8%
801-900	3.2	\$ 63.64	83.54	19.90	31.3%
901-1000	3.1	\$ 63.17	82.05	18.88	29.9%
1001-1100	3.4	\$ 68.63	88.86	20.23	29.5%
1101-1200	3.7	\$ 74.09	95.65	21.56	29.1%
1201-1300	3.9	\$ 79.55	101.23	21.67	27.2%
1301-1400	4.1	\$ 85.02	106.81	21.79	25.6%
1401-1500	4.4	\$ 90.48	113.61	23.13	25.6%
1501-1600	4.7	\$ 95.94	120.41	24.48	25.5%
1601-1700	4.5	\$ 101.40	121.09	19.69	19.4%
1701-1800	4.7	\$ 113.64	130.56	16.91	14.9%
1801-1900	4.9	\$ 119.48	136.35	16.87	14.1%
1901-2000	4.8	\$ 125.32	138.47	13.15	10.5%
2001-2500	6.1	\$ 154.51	171.11	16.60	10.7%
2501-3000	6.4	\$ 183.71	191.51	7.81	4.2%
3001-4000	8.5	\$ 242.09	250.67	8.58	3.5%
4001-5000	9.4	\$ 300.48	295.14	(5.33)	-1.8%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$) (B) - (A)	% (C) / (A)
601-700	4.4	94.04	130.74	36.70	39.0%
701-800	4.4	105.15	136.63	31.48	29.9%
801-900	4.9	116.25	151.23	34.98	30.1%
901-1000	5.3	127.11	164.09	36.98	29.1%
1001-1100	5.8	139.43	178.70	39.27	28.2%
1101-1200	6.3	149.68	193.30	43.62	29.1%
1201-1300	6.8	160.42	207.91	47.49	29.6%
1301-1400	7.1	170.43	219.02	48.59	28.5%
1401-1500	7.6	181.05	233.63	52.58	29.0%
1501-1600	8.1	191.43	248.23	56.81	29.7%
1601-1700	7.8	202.17	248.89	46.72	23.1%
1701-1800	7.5	212.91	249.54	36.63	17.2%
1801-1900	7.9	222.68	262.41	39.73	17.8%
1901-2000	7.8	233.42	266.55	33.13	14.2%
2001-2500	9.8	285.18	330.85	45.67	16.0%
2501-3000	10.3	342.64	369.00	26.37	7.7%
3001-4000	13.7	441.55	487.15	45.60	10.3%
4001-5000	15.2	550.89	572.17	21.28	3.9%

Winter		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$) (B) - (A)	% (C) / (A)
601-700	2.9	56.25	72.86	16.61	29.5%
701-800	2.9	61.93	76.36	14.43	23.3%
801-900	3.2	67.43	83.54	16.12	23.9%
901-1000	3.1	67.06	82.05	14.99	22.4%
1001-1100	3.4	71.81	88.86	17.05	23.7%
1101-1200	3.7	78.35	95.65	17.30	22.1%
1201-1300	3.9	83.10	101.23	18.12	21.8%
1301-1400	4.1	87.76	106.81	19.05	21.7%
1401-1500	4.4	92.87	113.61	20.73	22.3%
1501-1600	4.7	97.71	120.41	22.70	23.2%
1601-1700	4.5	102.82	121.09	18.27	17.8%
1701-1800	4.7	114.09	130.56	16.47	14.4%
1801-1900	4.9	118.88	136.35	17.47	14.7%
1901-2000	4.8	124.75	138.47	13.72	11.0%
2001-2500	6.1	151.14	171.11	19.97	13.2%
2501-3000	6.4	179.33	191.51	12.18	6.8%
3001-4000	8.5	227.98	250.67	22.69	10.0%
4001-5000	9.4	282.02	295.14	13.12	4.7%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$)	%
				(B) - (A)	(C) / (A)
601-700	4.4	91.63	130.74	39.11	42.7%
701-800	4.4	102.34	136.63	34.28	33.5%
801-900	4.9	113.05	151.23	38.18	33.8%
901-1000	5.3	123.76	164.09	40.33	32.6%
1001-1100	5.8	134.47	178.70	44.23	32.9%
1101-1200	6.3	145.17	193.30	48.13	33.2%
1201-1300	6.8	155.88	207.91	52.03	33.4%
1301-1400	7.1	166.59	219.02	52.44	31.5%
1401-1500	7.6	177.30	233.63	56.33	31.8%
1501-1600	8.1	188.00	248.23	60.23	32.0%
1601-1700	7.8	198.71	248.89	50.18	25.3%
1701-1800	7.5	209.42	249.54	40.12	19.2%
1801-1900	7.9	220.13	262.41	42.28	19.2%
1901-2000	7.8	230.84	266.55	35.71	15.5%
2001-2500	9.8	284.37	330.85	46.48	16.3%
2501-3000	10.3	337.91	369.00	31.09	9.2%
3001-4000	13.7	444.99	487.15	42.16	9.5%
4001-5000	15.2	552.07	572.17	20.10	3.6%

Winter		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$)	%
				(B) - (A)	(C) / (A)
601-700	2.9	54.53	72.86	18.32	33.6%
701-800	2.9	59.88	76.36	16.48	27.5%
801-900	3.2	65.37	83.54	18.18	27.8%
901-1000	3.1	64.92	82.05	17.12	26.4%
1001-1100	3.4	77.67	88.86	11.19	14.4%
1101-1200	3.7	83.14	95.65	12.51	15.1%
1201-1300	3.9	88.75	101.23	12.48	14.1%
1301-1400	4.1	94.22	106.81	12.59	13.4%
1401-1500	4.4	99.82	113.61	13.78	13.8%
1501-1600	4.7	105.29	120.41	15.12	14.4%
1601-1700	4.5	110.90	121.09	10.19	9.2%
1701-1800	4.7	123.24	130.56	7.31	5.9%
1801-1900	4.9	129.23	136.35	7.12	5.5%
1901-2000	4.8	135.08	138.47	3.39	2.5%
2001-2500	6.1	164.75	171.11	6.36	3.9%
2501-3000	6.4	194.29	191.51	(2.77)	-1.4%
3001-4000	8.5	253.49	250.67	(2.82)	-1.1%
4001-5000	9.4	312.69	295.14	(17.55)	-5.6%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$) (B) - (A)	% (C) / (A)
601-700	4.4	115.89	130.74	14.85	12.8%
701-800	4.4	120.46	136.63	16.17	13.4%
801-900	4.9	132.97	151.23	18.26	13.7%
901-1000	5.3	144.20	164.09	19.90	13.8%
1001-1100	5.8	156.00	178.70	22.70	14.6%
1101-1200	6.3	168.32	193.30	24.99	14.8%
1201-1300	6.8	180.50	207.91	27.40	15.2%
1301-1400	7.1	189.72	219.02	29.30	15.4%
1401-1500	7.6	201.88	233.63	31.75	15.7%
1501-1600	8.1	214.00	248.23	34.23	16.0%
1601-1700	7.8	215.06	248.89	33.83	15.7%
1701-1800	7.5	216.12	249.54	33.43	15.5%
1801-1900	7.9	227.12	262.41	35.29	15.5%
1901-2000	7.8	231.01	266.55	35.54	15.4%
2001-2500	9.8	284.76	330.85	46.09	16.2%
2501-3000	10.3	319.58	369.00	49.42	15.5%
3001-4000	13.7	420.25	487.15	66.90	15.9%
4001-5000	15.2	496.70	572.17	75.47	15.2%

Winter		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$) (B) - (A)	% (C) / (A)
601-700	2.9	65.10	72.86	7.76	11.9%
701-800	2.9	67.73	76.36	8.63	12.7%
801-900	3.2	73.76	83.54	9.79	13.3%
901-1000	3.1	72.39	82.05	9.65	13.3%
1001-1100	3.4	77.77	88.86	11.08	14.3%
1101-1200	3.7	83.09	95.65	12.56	15.1%
1201-1300	3.9	87.66	101.23	13.57	15.5%
1301-1400	4.1	92.05	106.81	14.76	16.0%
1401-1500	4.4	97.49	113.61	16.11	16.5%
1501-1600	4.7	102.95	120.41	17.46	17.0%
1601-1700	4.5	103.60	121.09	17.49	16.9%
1701-1800	4.7	111.29	130.56	19.27	17.3%
1801-1900	4.9	116.13	136.35	20.22	17.4%
1901-2000	4.8	117.97	138.47	20.50	17.4%
2001-2500	6.1	144.27	171.11	26.84	18.6%
2501-3000	6.4	161.09	191.51	30.42	18.9%
3001-4000	8.5	209.17	250.67	41.50	19.8%
4001-5000	9.4	246.39	295.14	48.76	19.8%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 customers moving to R-3

(excludes bill reduction from transferring adjustor rates to base rates)

Summer		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$) (B) - (A)	% (C) / (A)
601-700	4.4	114.79	130.74	15.95	13.9%
701-800	4.4	120.32	136.63	16.31	13.6%
801-900	4.9	132.60	151.23	18.64	14.1%
901-1000	5.3	143.53	164.09	20.57	14.3%
1001-1100	5.8	155.80	178.70	22.89	14.7%
1101-1200	6.3	168.08	193.30	25.22	15.0%
1201-1300	6.8	180.36	207.91	27.54	15.3%
1301-1400	7.1	189.94	219.02	29.08	15.3%
1401-1500	7.6	202.22	233.63	31.41	15.5%
1501-1600	8.1	214.50	248.23	33.73	15.7%
1601-1700	7.8	215.98	248.89	32.91	15.2%
1701-1800	7.5	217.46	249.54	32.08	14.8%
1801-1900	7.9	228.39	262.41	34.02	14.9%
1901-2000	7.8	232.57	266.55	33.98	14.6%
2001-2500	9.8	287.22	330.85	43.64	15.2%
2501-3000	10.3	321.62	369.00	47.39	14.7%
3001-4000	13.7	422.81	487.15	64.34	15.2%
4001-5000	15.2	498.36	572.17	73.82	14.8%

Winter		(A)	(B)	(C)	(D)
kWh block	On-Pk kW	Monthly Bill under Current Rates	Monthly Bill under Proposed Rates	Change	
				Amount (\$) (B) - (A)	% (C) / (A)
601-700	2.9	63.53	72.86	9.32	14.7%
701-800	2.9	66.37	76.36	9.99	15.1%
801-900	3.2	72.01	83.54	11.54	16.0%
901-1000	3.1	70.86	82.05	11.19	15.8%
1001-1100	3.4	77.13	88.86	11.73	15.2%
1101-1200	3.7	82.53	95.65	13.12	15.9%
1201-1300	3.9	87.02	101.23	14.21	16.3%
1301-1400	4.1	91.49	106.81	15.32	16.7%
1401-1500	4.4	96.91	113.61	16.70	17.2%
1501-1600	4.7	102.31	120.41	18.11	17.7%
1601-1700	4.5	103.08	121.09	18.02	17.5%
1701-1800	4.7	110.80	130.56	19.76	17.8%
1801-1900	4.9	115.47	136.35	20.88	18.1%
1901-2000	4.8	117.33	138.47	21.14	18.0%
2001-2500	6.1	143.43	171.11	27.68	19.3%
2501-3000	6.4	160.22	191.51	31.30	19.5%
3001-4000	8.5	207.75	250.67	42.92	20.7%
4001-5000	9.4	244.13	295.14	51.02	20.9%

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	Change	
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
			(C) - (B)	(D) / (B)
200	27.92	32.22	4.30	15.4%
250	32.77	37.80	5.03	15.3%
300	37.61	43.38	5.77	15.3%
350	42.45	48.96	6.51	15.3%
400	47.30	54.54	7.24	15.3%
450	54.21	62.50	8.29	15.3%
500	61.12	70.46	9.34	15.3%
550	68.02	78.42	10.40	15.3%
600	74.93	86.38	11.45	15.3%
650	81.84	94.34	12.50	15.3%
700	88.75	102.30	13.55	15.3%
750	95.66	110.26	14.60	15.3%
800	102.57	118.22	15.65	15.3%
850	110.65	127.54	16.89	15.3%
900	118.73	136.85	18.12	15.3%
950	126.82	146.16	19.34	15.2%
1,000	134.90	155.48	20.58	15.3%
1,100	151.07	174.11	23.04	15.3%
1,200	167.23	192.73	25.50	15.2%
1,300	183.40	211.36	27.96	15.2%
1,400	199.57	229.99	30.42	15.2%
1,500	215.74	248.61	32.87	15.2%
1,600	231.90	267.24	35.34	15.2%
1,700	248.07	285.87	37.80	15.2%
1,800	264.24	304.49	40.25	15.2%
1,900	280.40	323.12	42.72	15.2%
2,000	296.57	341.75	45.18	15.2%
2,200	328.90	379.00	50.10	15.2%
2,400	361.24	416.26	55.02	15.2%
2,600	393.57	453.51	59.94	15.2%
2,800	425.91	490.76	64.85	15.2%
3,000	458.24	528.02	69.78	15.2%
4,000	630.81	726.65	95.84	15.2%
5,000	803.38	925.28	121.90	15.2%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-12 Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
			Amount (\$)	%
			(C) - (B)	(D) / (B)
200	27.38	31.60	4.22	15.4%
250	32.09	37.03	4.94	15.4%
300	36.80	42.45	5.65	15.4%
350	41.51	47.88	6.37	15.3%
400	46.22	53.30	7.08	15.3%
450	50.93	58.73	7.80	15.3%
500	55.64	64.16	8.52	15.3%
550	60.34	69.58	9.24	15.3%
600	65.05	75.01	9.96	15.3%
650	69.76	80.43	10.67	15.3%
700	74.47	85.86	11.39	15.3%
750	79.18	91.28	12.10	15.3%
800	83.89	96.71	12.82	15.3%
850	88.59	102.13	13.54	15.3%
900	93.30	107.56	14.26	15.3%
950	98.01	112.98	14.97	15.3%
1,000	102.72	118.41	15.69	15.3%
1,100	112.14	129.26	17.12	15.3%
1,200	121.55	140.11	18.56	15.3%
1,300	130.97	150.96	19.99	15.3%
1,400	140.39	161.81	21.42	15.3%
1,500	149.81	172.67	22.86	15.3%
1,600	159.22	183.52	24.30	15.3%
1,700	168.64	194.37	25.73	15.3%
1,800	178.06	205.22	27.16	15.3%
1,900	187.47	216.07	28.60	15.3%
2,000	196.89	226.92	30.03	15.3%
2,200	215.72	248.62	32.90	15.3%
2,400	234.56	270.32	35.76	15.2%
2,600	253.39	292.03	38.64	15.2%
2,800	272.23	313.73	41.50	15.2%
3,000	291.06	335.43	44.37	15.2%
4,000	385.23	443.94	58.71	15.2%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)		(E)
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change		
			Amount (\$)	%	
			(C) - (B)	(D) / (B)	
200	38.16	44.16	6.00	15.7%	
250	43.53	50.38	6.85	15.7%	
300	48.90	56.60	7.70	15.7%	
350	54.27	62.82	8.55	15.8%	
400	59.64	69.04	9.40	15.8%	
450	65.01	75.26	10.25	15.8%	
500	70.38	81.48	11.10	15.8%	
550	75.75	87.69	11.94	15.8%	
600	81.12	93.91	12.79	15.8%	
650	86.49	100.13	13.64	15.8%	
700	91.86	106.35	14.49	15.8%	
750	97.23	112.57	15.34	15.8%	
800	102.60	118.79	16.19	15.8%	
850	107.97	125.00	17.03	15.8%	
900	113.34	131.22	17.88	15.8%	
950	118.71	137.44	18.73	15.8%	
1,000	124.08	143.66	19.58	15.8%	
1,100	134.82	156.10	21.28	15.8%	
1,200	145.56	168.53	22.97	15.8%	
1,300	156.30	180.97	24.67	15.8%	
1,400	167.04	193.41	26.37	15.8%	
1,500	177.78	205.85	28.07	15.8%	
1,600	188.52	218.28	29.76	15.8%	
1,700	199.26	230.72	31.46	15.8%	
1,800	210.00	243.16	33.16	15.8%	
1,900	220.74	255.59	34.85	15.8%	
2,000	231.48	268.03	36.55	15.8%	
2,200	252.96	292.90	39.94	15.8%	
2,400	274.44	317.78	43.34	15.8%	
2,600	295.92	342.65	46.73	15.8%	
2,800	317.40	367.53	50.13	15.8%	
3,000	338.88	392.40	53.52	15.8%	

ET-1 Summer Average Energy On-Peak: 41%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-1 Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
			Amount (\$)	%
			(C) - (B)	(D) / (B)
200	33.76	38.99	5.23	15.5%
250	38.03	43.91	5.88	15.5%
300	42.30	48.84	6.54	15.5%
350	46.57	53.76	7.19	15.4%
400	50.84	58.69	7.85	15.4%
450	55.11	63.61	8.50	15.4%
500	59.38	68.53	9.15	15.4%
550	63.65	73.46	9.81	15.4%
600	67.92	78.38	10.46	15.4%
650	72.19	83.31	11.12	15.4%
700	76.46	88.23	11.77	15.4%
750	80.73	93.16	12.43	15.4%
800	85.00	98.08	13.08	15.4%
850	89.27	103.00	13.73	15.4%
900	93.54	107.93	14.39	15.4%
950	97.81	112.85	15.04	15.4%
1,000	102.08	117.78	15.70	15.4%
1,100	110.62	127.63	17.01	15.4%
1,200	119.16	137.48	18.32	15.4%
1,300	127.70	147.32	19.62	15.4%
1,400	136.24	157.17	20.93	15.4%
1,500	144.78	167.02	22.24	15.4%
1,600	153.32	176.87	23.55	15.4%
1,700	161.85	186.72	24.87	15.4%
1,800	170.39	196.57	26.18	15.4%
1,900	178.93	206.42	27.49	15.4%
2,000	187.47	216.27	28.80	15.4%
2,200	204.55	235.96	31.41	15.4%
2,400	221.63	255.66	34.03	15.4%
2,600	238.71	275.36	36.65	15.4%
2,800	255.79	295.06	39.27	15.4%
3,000	272.87	314.75	41.88	15.3%

ET-1 Winter Average Energy On-Peak: 33%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)		(E)
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change		
			Amount (\$)	%	
			(C) - (B)	(D) / (B)	
200	38.24	44.22	5.98	15.6%	
250	43.63	50.45	6.82	15.6%	
300	49.02	56.68	7.66	15.6%	
350	54.41	62.92	8.51	15.6%	
400	59.80	69.15	9.35	15.6%	
450	65.20	75.38	10.18	15.6%	
500	70.59	81.61	11.02	15.6%	
550	75.98	87.84	11.86	15.6%	
600	81.37	94.08	12.71	15.6%	
650	86.76	100.31	13.55	15.6%	
700	92.15	106.54	14.39	15.6%	
750	97.54	112.77	15.23	15.6%	
800	102.93	119.01	16.08	15.6%	
850	108.32	125.24	16.92	15.6%	
900	113.71	131.47	17.76	15.6%	
950	119.10	137.70	18.60	15.6%	
1,000	124.49	143.93	19.44	15.6%	
1,100	135.27	156.40	21.13	15.6%	
1,200	146.05	168.86	22.81	15.6%	
1,300	156.84	181.33	24.49	15.6%	
1,400	167.62	193.79	26.17	15.6%	
1,500	178.40	206.26	27.86	15.6%	
1,600	189.18	218.72	29.54	15.6%	
1,700	199.96	231.18	31.22	15.6%	
1,800	210.74	243.65	32.91	15.6%	
1,900	221.52	256.11	34.59	15.6%	
2,000	232.30	268.58	36.28	15.6%	
2,200	253.87	293.51	39.64	15.6%	
2,400	275.43	318.44	43.01	15.6%	
2,600	296.99	343.36	46.37	15.6%	
2,800	318.55	368.29	49.74	15.6%	
3,000	340.12	393.22	53.10	15.6%	

ET-2 Summer Average Energy On-Peak: 25%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ET-2 Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
			Amount (\$)	%
			(C) - (B)	(D) / (B)
200	34.07	39.28	5.21	15.3%
250	38.42	44.27	5.85	15.2%
300	42.77	49.27	6.50	15.2%
350	47.12	54.27	7.15	15.2%
400	51.47	59.26	7.79	15.1%
450	55.82	64.26	8.44	15.1%
500	60.17	69.26	9.09	15.1%
550	64.52	74.25	9.73	15.1%
600	68.86	79.25	10.39	15.1%
650	73.21	84.25	11.04	15.1%
700	77.56	89.24	11.68	15.1%
750	81.91	94.24	12.33	15.1%
800	86.26	99.24	12.98	15.0%
850	90.61	104.23	13.62	15.0%
900	94.96	109.23	14.27	15.0%
950	99.31	114.23	14.92	15.0%
1,000	103.65	119.22	15.57	15.0%
1,100	112.35	129.22	16.87	15.0%
1,200	121.05	139.21	18.16	15.0%
1,300	129.75	149.20	19.45	15.0%
1,400	138.44	159.20	20.76	15.0%
1,500	147.14	169.19	22.05	15.0%
1,600	155.84	179.18	23.34	15.0%
1,700	164.54	189.18	24.64	15.0%
1,800	173.23	199.17	25.94	15.0%
1,900	181.93	209.16	27.23	15.0%
2,000	190.63	219.16	28.53	15.0%
2,200	208.02	239.14	31.12	15.0%
2,400	225.42	259.13	33.71	15.0%
2,600	242.81	279.11	36.30	14.9%
2,800	260.21	299.10	38.89	14.9%
3,000	277.60	319.09	41.49	14.9%

ET-2 Winter Average Energy On-Peak: 19%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
					(E) - (D)	(F) / (D)
3	20%	438	80.92	93.68	12.76	15.8%
3	30%	657	92.71	107.35	14.64	15.8%
3	40%	876	104.50	121.01	16.51	15.8%
3	50%	1,095	116.30	134.67	18.37	15.8%
3	75%	1,643	145.81	168.85	23.04	15.8%
5	20%	730	123.74	143.28	19.54	15.8%
5	30%	1,095	143.40	166.05	22.65	15.8%
5	40%	1,460	163.05	188.82	25.77	15.8%
5	50%	1,825	182.71	211.58	28.87	15.8%
5	75%	2,738	231.87	268.53	36.66	15.8%
8	20%	1,168	187.98	217.68	29.70	15.8%
8	30%	1,752	219.43	254.10	34.67	15.8%
8	40%	2,336	250.87	290.53	39.66	15.8%
8	50%	2,920	282.32	326.96	44.64	15.8%
8	75%	4,380	360.95	418.03	57.08	15.8%
10	20%	1,460	230.80	267.27	36.47	15.8%
10	30%	2,190	270.11	312.81	42.70	15.8%
10	40%	2,920	309.42	358.34	48.92	15.8%
10	50%	3,650	348.73	403.88	55.15	15.8%
10	75%	5,475	447.01	517.72	70.71	15.8%
12	20%	1,752	273.63	316.87	43.24	15.8%
12	30%	2,628	320.80	371.51	50.71	15.8%
12	40%	3,504	367.97	426.15	58.18	15.8%
12	50%	4,380	415.15	480.80	65.65	15.8%
12	75%	6,570	533.08	617.40	84.32	15.8%
15	20%	2,190	337.86	391.26	53.40	15.8%
15	30%	3,285	396.83	459.57	62.74	15.8%
15	40%	4,380	455.80	527.87	72.07	15.8%
15	50%	5,475	514.76	596.17	81.41	15.8%
15	75%	8,213	662.20	766.96	104.76	15.8%

ECT-1R Summer Average Energy On-Peak: 40%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-1R Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
					(E) - (D)	(F) / (D)
3	20%	438	64.60	74.78	10.18	15.8%
3	30%	657	74.46	86.19	11.73	15.8%
3	40%	876	84.31	97.61	13.30	15.8%
3	50%	1,095	94.17	109.03	14.86	15.8%
3	75%	1,643	118.84	137.60	18.76	15.8%
5	20%	730	96.54	111.77	15.23	15.8%
5	30%	1,095	112.97	130.80	17.83	15.8%
5	40%	1,460	129.40	149.83	20.43	15.8%
5	50%	1,825	145.83	168.85	23.02	15.8%
5	75%	2,738	186.93	216.45	29.52	15.8%
8	20%	1,168	144.46	167.26	22.80	15.8%
8	30%	1,752	170.75	197.70	26.95	15.8%
8	40%	2,336	197.04	228.15	31.11	15.8%
8	50%	2,920	223.33	258.59	35.26	15.8%
8	75%	4,380	289.05	334.70	45.65	15.8%
10	20%	1,460	176.40	204.25	27.85	15.8%
10	30%	2,190	209.27	242.31	33.04	15.8%
10	40%	2,920	242.13	280.36	38.23	15.8%
10	50%	3,650	274.99	318.42	43.43	15.8%
10	75%	5,475	357.14	413.56	56.42	15.8%
12	20%	1,752	208.35	241.24	32.89	15.8%
12	30%	2,628	247.78	286.91	39.13	15.8%
12	40%	3,504	287.22	332.58	45.36	15.8%
12	50%	4,380	326.65	378.24	51.59	15.8%
12	75%	6,570	425.24	492.41	67.17	15.8%
15	20%	2,190	256.27	296.73	40.46	15.8%
15	30%	3,285	305.56	353.81	48.25	15.8%
15	40%	4,380	354.85	410.90	56.05	15.8%
15	50%	5,475	404.14	467.98	63.84	15.8%
15	75%	8,213	527.40	610.72	83.32	15.8%

ECT-1R Winter Average Energy On-Peak: 33%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 Solar Legacy Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount (\$) (E) - (D)	% (F) / (D)
3	20%	438	81.28	94.01	12.73	15.7%
3	30%	657	93.33	107.95	14.62	15.7%
3	40%	876	105.38	121.89	16.51	15.7%
3	50%	1,095	117.44	135.83	18.39	15.7%
3	75%	1,643	147.59	170.71	23.12	15.7%
5	20%	730	124.35	143.82	19.47	15.7%
5	30%	1,095	144.44	167.06	22.62	15.7%
5	40%	1,460	164.52	190.29	25.77	15.7%
5	50%	1,825	184.61	213.52	28.91	15.7%
5	75%	2,738	234.85	271.63	36.78	15.7%
8	20%	1,168	188.95	218.54	29.59	15.7%
8	30%	1,752	221.09	255.71	34.62	15.7%
8	40%	2,336	253.23	292.89	39.66	15.7%
8	50%	2,920	285.36	330.06	44.70	15.7%
8	75%	4,380	365.70	422.98	57.28	15.7%
10	20%	1,460	232.02	268.36	36.34	15.7%
10	30%	2,190	272.19	314.82	42.63	15.7%
10	40%	2,920	312.36	361.28	48.92	15.7%
10	50%	3,650	352.53	407.75	55.22	15.7%
10	75%	5,475	452.96	523.91	70.95	15.7%
12	20%	1,752	275.09	318.17	43.08	15.7%
12	30%	2,628	323.29	373.93	50.64	15.7%
12	40%	3,504	371.50	429.68	58.18	15.7%
12	50%	4,380	419.70	485.44	65.74	15.7%
12	75%	6,570	540.21	624.83	84.62	15.7%
15	20%	2,190	339.69	392.89	53.20	15.7%
15	30%	3,285	399.95	462.59	62.64	15.7%
15	40%	4,380	460.20	532.28	72.08	15.7%
15	50%	5,475	520.46	601.98	81.52	15.7%
15	75%	8,213	671.12	776.25	105.13	15.7%

ECT-2 Summer Average Energy On-Peak: 24%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
ECT-2 Solar Legacy Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
					(E) - (D)	(F) / (D)
3	20%	438	63.86	73.86	10.00	15.7%
3	30%	657	73.50	85.01	11.51	15.7%
3	40%	876	83.14	96.16	13.02	15.7%
3	50%	1,095	92.78	107.31	14.53	15.7%
3	75%	1,643	116.91	135.21	18.30	15.7%
5	20%	730	95.32	110.24	14.92	15.7%
5	30%	1,095	111.38	128.82	17.44	15.7%
5	40%	1,460	127.45	147.41	19.96	15.7%
5	50%	1,825	143.52	165.99	22.47	15.7%
5	75%	2,738	183.71	212.47	28.76	15.7%
8	20%	1,168	142.50	164.81	22.31	15.7%
8	30%	1,752	168.21	194.54	26.33	15.7%
8	40%	2,336	193.92	224.27	30.35	15.7%
8	50%	2,920	219.62	254.01	34.39	15.7%
8	75%	4,380	283.90	328.34	44.44	15.7%
10	20%	1,460	173.95	201.19	27.24	15.7%
10	30%	2,190	206.09	238.35	32.26	15.7%
10	40%	2,920	238.22	275.52	37.30	15.7%
10	50%	3,650	270.36	312.69	42.33	15.7%
10	75%	5,475	350.70	405.61	54.91	15.7%
12	20%	1,752	205.41	237.56	32.15	15.7%
12	30%	2,628	243.97	282.17	38.20	15.7%
12	40%	3,504	282.53	326.77	44.24	15.7%
12	50%	4,380	321.10	371.37	50.27	15.7%
12	75%	6,570	417.50	482.87	65.37	15.7%
15	20%	2,190	252.59	292.13	39.54	15.7%
15	30%	3,285	300.79	347.88	47.09	15.7%
15	40%	4,380	349.00	403.64	54.64	15.7%
15	50%	5,475	397.20	459.39	62.19	15.7%
15	75%	8,213	517.73	598.79	81.06	15.7%

ECT-2 Winter Average Energy On-Peak: 18%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates
E-20 Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
On- Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
					Amount (\$)	%
					(E) - (D)	(F) / (D)
15	20%	2,190	271.95	336.51	64.56	23.7%
15	30%	3,285	374.02	445.97	71.95	19.2%
15	40%	4,380	476.09	555.43	79.34	16.7%
15	50%	5,475	578.16	664.89	86.73	15.0%
15	75%	8,213	833.38	938.58	105.20	12.6%
30	20%	4,380	511.95	612.43	100.48	19.6%
30	30%	6,570	716.09	831.34	115.25	16.1%
30	40%	8,760	920.23	1,050.26	130.03	14.1%
30	50%	10,950	1,124.37	1,269.17	144.80	12.9%
30	75%	16,425	1,634.71	1,816.46	181.75	11.1%
50	20%	7,300	831.96	980.31	148.35	17.8%
50	30%	10,950	1,172.19	1,345.17	172.98	14.8%
50	40%	14,600	1,512.41	1,710.03	197.62	13.1%
50	50%	18,250	1,852.64	2,074.89	222.25	12.0%
50	75%	27,375	2,703.21	2,987.03	283.82	10.5%
100	20%	14,600	1,631.96	1,900.03	268.07	16.4%
100	30%	21,900	2,312.42	2,629.74	317.32	13.7%
100	40%	29,200	2,992.88	3,359.46	366.58	12.2%
100	50%	36,500	3,673.34	4,089.17	415.83	11.3%
100	75%	54,750	5,374.48	5,913.46	538.98	10.0%
150	20%	21,900	2,431.97	2,819.74	387.77	15.9%
150	30%	32,850	3,452.66	3,914.32	461.66	13.4%
150	40%	43,800	4,473.34	5,008.89	535.55	12.0%
150	50%	54,750	5,494.03	6,103.46	609.43	11.1%
150	75%	82,125	8,045.74	8,839.89	794.15	9.9%

General Service TOU Average Energy On-Peak: 31%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-20 Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
On-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$) (E) - (D)	% (F) / (D)
15	20%	2,190	245.75	312.43	66.68	27.1%
15	30%	3,285	336.48	409.84	73.36	21.8%
15	40%	4,380	427.21	507.25	80.04	18.7%
15	50%	5,475	517.93	604.67	86.74	16.7%
15	75%	8,213	744.80	848.24	103.44	13.9%
30	20%	4,380	459.55	564.25	104.70	22.8%
30	30%	6,570	641.00	759.08	118.08	18.4%
30	40%	8,760	822.46	953.91	131.45	16.0%
30	50%	10,950	1,003.92	1,148.73	144.81	14.4%
30	75%	16,425	1,457.56	1,635.80	178.24	12.2%
50	20%	7,300	744.61	900.02	155.41	20.9%
50	30%	10,950	1,047.04	1,224.73	177.69	17.0%
50	40%	14,600	1,349.47	1,549.44	199.97	14.8%
50	50%	18,250	1,651.90	1,874.15	222.25	13.5%
50	75%	27,375	2,407.97	2,685.93	277.96	11.5%
100	20%	14,600	1,457.27	1,739.44	282.17	19.4%
100	30%	21,900	2,062.13	2,388.86	326.73	15.8%
100	40%	29,200	2,666.99	3,038.28	371.29	13.9%
100	50%	36,500	3,271.85	3,687.71	415.86	12.7%
100	75%	54,750	4,784.00	5,311.26	527.26	11.0%
150	20%	21,900	2,169.93	2,578.86	408.93	18.8%
150	30%	32,850	3,077.22	3,553.00	475.78	15.5%
150	40%	43,800	3,984.51	4,527.13	542.62	13.6%
150	50%	54,750	4,891.80	5,501.26	609.46	12.5%
150	75%	82,125	7,160.02	7,936.59	776.57	10.8%

General Service TOU Average Energy On-Peak: 31%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-30 Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
			Amount (\$)	%
			(C) - (B)	(D) / (B)
30	13.67	16.29	2.62	19.2%
40	15.11	17.67	2.56	16.9%
50	16.56	19.05	2.49	15.0%
60	18.00	20.42	2.42	13.4%
70	19.45	21.80	2.35	12.1%
80	20.89	23.18	2.29	11.0%
90	22.34	24.56	2.22	9.9%
100	23.79	25.94	2.15	9.0%
125	27.40	29.39	1.99	7.3%
150	31.01	32.84	1.83	5.9%
175	34.63	36.28	1.65	4.8%
200	38.24	39.73	1.49	3.9%
225	41.85	43.18	1.33	3.2%
250	45.47	46.63	1.16	2.6%
275	49.08	50.08	1.00	2.0%
300	52.70	53.52	0.82	1.6%
325	56.31	56.97	0.66	1.2%
350	59.92	60.42	0.50	0.8%
375	63.54	63.87	0.33	0.5%
400	67.15	67.31	0.16	0.2%
425	70.76	70.76	-	0.0%
450	74.38	74.21	(0.17)	-0.2%
475	77.99	77.66	(0.33)	-0.4%
500	81.61	81.11	(0.50)	-0.6%
600	96.06	94.90	(1.16)	-1.2%
700	110.52	108.69	(1.83)	-1.7%
800	124.97	122.48	(2.49)	-2.0%
900	139.43	136.27	(3.16)	-2.3%
1,000	153.88	150.06	(3.82)	-2.5%
1,500	226.16	219.02	(7.14)	-3.2%
2,000	298.43	287.97	(10.46)	-3.5%
2,500	370.71	356.93	(13.78)	-3.7%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-30 Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
			Amount (\$)	%
			(C) - (B)	(D) / (B)
30	13.23	15.88	2.65	20.0%
40	14.52	17.13	2.61	18.0%
50	15.82	18.37	2.55	16.1%
60	17.12	19.62	2.50	14.6%
70	18.42	20.86	2.44	13.2%
80	19.72	22.10	2.38	12.1%
90	21.02	23.35	2.33	11.1%
100	22.31	24.59	2.28	10.2%
125	25.56	27.70	2.14	8.4%
150	28.81	30.81	2.00	6.9%
175	32.05	33.93	1.88	5.9%
200	35.30	37.04	1.74	4.9%
225	38.54	40.15	1.61	4.2%
250	41.79	43.26	1.47	3.5%
275	45.04	46.37	1.33	3.0%
300	48.28	49.48	1.20	2.5%
325	51.53	52.59	1.06	2.1%
350	54.77	55.70	0.93	1.7%
375	58.02	58.81	0.79	1.4%
400	61.27	61.92	0.65	1.1%
425	64.51	65.03	0.52	0.8%
450	67.76	68.14	0.38	0.6%
475	71.00	71.25	0.25	0.4%
500	74.25	74.37	0.12	0.2%
600	87.23	86.81	(0.42)	-0.5%
700	100.22	99.25	(0.97)	-1.0%
800	113.20	111.69	(1.51)	-1.3%
900	126.19	124.14	(2.05)	-1.6%
1,000	139.17	136.58	(2.59)	-1.9%
1,500	204.09	198.80	(5.29)	-2.6%
2,000	269.01	261.01	(8.00)	-3.0%
2,500	333.93	323.23	(10.70)	-3.2%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$) (E) - (D)	% (F) / (D)
5	15%	548	94.34	127.11	32.77	34.7%
5	30%	1,095	168.39	184.81	16.42	9.8%
5	45%	1,643	242.57	242.61	0.04	0.0%
5	60%	2,190	316.62	300.31	(16.31)	-5.2%
5	75%	2,738	390.80	358.12	(32.68)	-8.4%
10	15%	1,095	168.39	219.31	50.92	30.2%
10	30%	2,190	316.62	334.81	18.19	5.7%
10	45%	3,285	464.85	450.32	(14.53)	-3.1%
10	60%	4,380	613.08	565.82	(47.26)	-7.7%
10	75%	5,475	732.29	681.33	(50.96)	-7.0%
15	15%	1,643	242.57	311.61	69.04	28.5%
15	30%	3,285	464.85	484.82	19.97	4.3%
15	45%	4,928	687.26	658.13	(29.13)	-4.2%
15	60%	6,570	813.61	831.34	17.73	2.2%
15	75%	8,213	935.64	1,004.65	69.01	7.4%
20	15%	2,190	316.62	403.81	87.19	27.5%
20	30%	4,380	613.08	634.82	21.74	3.5%
20	45%	6,570	813.61	865.84	52.23	6.4%
20	60%	8,760	976.27	1,096.85	120.58	12.4%
20	75%	10,950	1,138.92	1,327.86	188.94	16.6%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
 - 0 - 99 kW = self contained
 - 100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)		(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change		
					Amount (\$)	%	
					(E) - (D)	(F) / (D)	
5	15%	548	84.65	116.60	31.95	37.7%	
5	30%	1,095	149.03	163.81	14.78	9.9%	
5	45%	1,643	213.52	211.11	(2.41)	-1.1%	
5	60%	2,190	277.90	258.32	(19.58)	-7.0%	
5	75%	2,738	342.40	305.62	(36.78)	-10.7%	
10	15%	1,095	149.03	198.31	49.28	33.1%	
10	30%	2,190	277.90	292.82	14.92	5.4%	
10	45%	3,285	406.77	387.33	(19.44)	-4.8%	
10	60%	4,380	535.64	481.84	(53.80)	-10.0%	
10	75%	5,475	635.49	576.35	(59.14)	-9.3%	
15	15%	1,643	213.52	280.11	66.59	31.2%	
15	30%	3,285	406.77	421.83	15.06	3.7%	
15	45%	4,928	600.14	563.64	(36.50)	-6.1%	
15	60%	6,570	697.44	705.36	7.92	1.1%	
15	75%	8,213	790.40	847.16	56.76	7.2%	
20	15%	2,190	277.90	361.82	83.92	30.2%	
20	30%	4,380	535.64	550.84	15.20	2.8%	
20	45%	6,570	697.44	739.86	42.42	6.1%	
20	60%	8,760	821.35	928.88	107.53	13.1%	
20	75%	10,950	945.26	1,117.89	172.63	18.3%	

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
 - 0 - 99 kW = self contained
 - 100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Transition Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
					Amount (\$) (E) - (D)	% (F) / (D)
5	15%	548	94.34	108.86	14.52	15.4%
5	30%	1,095	168.39	182.78	14.39	8.5%
5	45%	1,643	242.57	256.84	14.27	5.9%
5	60%	2,190	316.62	330.76	14.14	4.5%
5	75%	2,738	390.80	404.81	14.01	3.6%
10	15%	1,095	168.39	182.78	14.39	8.5%
10	30%	2,190	316.62	330.76	14.14	4.5%
10	45%	3,285	464.85	478.73	13.88	3.0%
10	60%	4,380	613.08	626.71	13.63	2.2%
10	75%	5,475	732.29	746.66	14.37	2.0%
15	15%	1,643	242.57	256.84	14.27	5.9%
15	30%	3,285	464.85	478.73	13.88	3.0%
15	45%	4,928	687.26	700.77	13.51	2.0%
15	60%	6,570	813.61	830.01	16.40	2.0%
15	75%	8,213	935.64	955.07	19.43	2.1%
20	15%	2,190	316.62	330.76	14.14	4.5%
20	30%	4,380	613.08	626.71	13.63	2.2%
20	45%	6,570	813.61	830.01	16.40	2.0%
20	60%	8,760	976.27	996.71	20.44	2.1%
20	75%	10,950	1,138.92	1,163.41	24.49	2.2%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
 - 0 - 99 kW = self contained
 - 100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 XS Transition Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)		(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change		
					Amount (\$)	%	
					(E) - (D)	(F) / (D)	
5	15%	548	84.65	99.45	14.80	17.5%	
5	30%	1,095	149.03	163.98	14.95	10.0%	
5	45%	1,643	213.52	228.62	15.10	7.1%	
5	60%	2,190	277.90	293.15	15.25	5.5%	
5	75%	2,738	342.40	357.80	15.40	4.5%	
10	15%	1,095	149.03	163.98	14.95	10.0%	
10	30%	2,190	277.90	293.15	15.25	5.5%	
10	45%	3,285	406.77	422.33	15.56	3.8%	
10	60%	4,380	535.64	551.51	15.87	3.0%	
10	75%	5,475	635.49	652.50	17.01	2.7%	
15	15%	1,643	213.52	228.62	15.10	7.1%	
15	30%	3,285	406.77	422.33	15.56	3.8%	
15	45%	4,928	600.14	616.16	16.02	2.7%	
15	60%	6,570	697.44	716.71	19.27	2.8%	
15	75%	8,213	790.40	813.06	22.66	2.9%	
20	15%	2,190	277.90	293.15	15.25	5.5%	
20	30%	4,380	535.64	551.51	15.87	3.0%	
20	45%	6,570	697.44	716.71	19.27	2.8%	
20	60%	8,760	821.35	845.14	23.79	2.9%	
20	75%	10,950	945.26	973.56	28.30	3.0%	

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

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- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
 - 0 - 99 kW = self contained
 - 100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 S Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount (\$) (E) - (D)	% (F) / (D)
21	15%	2,300	464.30	522.40	58.10	12.5%
21	30%	4,599	685.67	754.21	68.54	10.0%
21	45%	6,899	829.58	904.52	74.94	9.0%
21	60%	9,198	973.43	1,054.76	81.33	8.4%
21	75%	11,498	1,117.34	1,205.06	87.72	7.9%
40	15%	4,380	866.04	963.47	97.43	11.3%
40	30%	8,760	1,287.79	1,405.11	117.32	9.1%
40	45%	13,140	1,561.85	1,691.34	129.49	8.3%
40	60%	17,520	1,835.91	1,977.57	141.66	7.7%
40	75%	21,900	2,109.96	2,263.81	153.85	7.3%
60	15%	6,570	1,288.98	1,427.80	138.82	10.8%
60	30%	13,140	1,921.61	2,090.26	168.65	8.8%
60	45%	19,710	2,332.69	2,519.61	186.92	8.0%
60	60%	26,280	2,743.78	2,948.96	205.18	7.5%
60	75%	32,850	3,154.86	3,378.31	223.45	7.1%
80	15%	8,760	1,711.92	1,892.13	180.21	10.5%
80	30%	17,520	2,555.43	2,775.41	219.98	8.6%
80	45%	26,280	3,103.54	3,347.88	244.34	7.9%
80	60%	35,040	3,651.65	3,920.34	268.69	7.4%
80	75%	43,800	4,199.77	4,492.81	293.04	7.0%
90	15%	9,855	1,923.39	2,124.30	200.91	10.4%
90	30%	19,710	2,872.33	3,117.99	245.66	8.6%
90	45%	29,565	3,488.96	3,762.01	273.05	7.8%
90	60%	39,420	4,105.59	4,406.04	300.45	7.3%
90	75%	49,275	4,722.22	5,050.06	327.84	6.9%
100	15%	10,950	2,134.86	2,356.47	221.61	10.4%
100	30%	21,900	3,189.24	3,460.57	271.33	8.5%
100	45%	32,850	3,874.38	4,176.15	301.77	7.8%
100	60%	43,800	4,559.53	4,891.73	332.20	7.3%
100	75%	54,750	5,244.67	5,607.31	362.64	6.9%

Supporting Schedules:

N/A

Recap Schedules:

N/A

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- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 S Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
					Amount (\$) (E) - (D)	% (F) / (D)
21	15%	2,300	427.06	483.26	56.20	13.2%
21	30%	4,599	611.21	675.95	64.74	10.6%
21	45%	6,899	717.88	787.18	69.30	9.7%
21	60%	9,198	824.51	898.36	73.85	9.0%
21	75%	11,498	931.19	1,009.58	78.39	8.4%
40	15%	4,380	795.13	888.92	93.79	11.8%
40	30%	8,760	1,145.97	1,256.03	110.06	9.6%
40	45%	13,140	1,349.11	1,467.85	118.74	8.8%
40	60%	17,520	1,552.26	1,679.67	127.41	8.2%
40	75%	21,900	1,755.40	1,891.48	136.08	7.8%
60	15%	6,570	1,182.61	1,315.98	133.37	11.3%
60	30%	13,140	1,708.87	1,866.65	157.78	9.2%
60	45%	19,710	2,013.59	2,184.38	170.79	8.5%
60	60%	26,280	2,318.31	2,502.10	183.79	7.9%
60	75%	32,850	2,623.02	2,819.83	196.81	7.5%
80	15%	8,760	1,570.10	1,743.04	172.94	11.0%
80	30%	17,520	2,271.78	2,477.27	205.49	9.0%
80	45%	26,280	2,678.07	2,900.90	222.83	8.3%
80	60%	35,040	3,084.36	3,324.53	240.17	7.8%
80	75%	43,800	3,490.64	3,748.17	257.53	7.4%
90	15%	9,855	1,763.84	1,956.57	192.73	10.9%
90	30%	19,710	2,553.23	2,782.58	229.35	9.0%
90	45%	29,565	3,010.30	3,259.16	248.86	8.3%
90	60%	39,420	3,467.38	3,735.75	268.37	7.7%
90	75%	49,275	3,924.45	4,212.34	287.89	7.3%
100	15%	10,950	1,957.58	2,170.10	212.52	10.9%
100	30%	21,900	2,834.68	3,087.88	253.20	8.9%
100	45%	32,850	3,342.54	3,617.43	274.89	8.2%
100	60%	43,800	3,850.40	4,146.97	296.57	7.7%
100	75%	54,750	4,358.27	4,676.51	318.24	7.3%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

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- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 M Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$) (E) - (D)	% (F) / (D)
101	15%	11,060	2,161.78	2,444.77	282.99	13.1%
101	30%	22,119	3,182.06	3,531.65	349.59	11.0%
101	45%	33,179	3,855.72	4,247.79	392.07	10.2%
101	60%	44,238	4,529.33	4,963.86	434.53	9.6%
101	75%	55,298	5,202.99	5,679.99	477.00	9.2%
150	15%	16,425	2,955.92	3,349.63	393.71	13.3%
150	30%	32,850	4,471.26	4,963.89	492.63	11.0%
150	45%	49,275	5,471.71	6,027.41	555.70	10.2%
150	60%	65,700	6,472.16	7,090.93	618.77	9.6%
150	75%	82,125	7,472.60	8,154.44	681.84	9.1%
200	15%	21,900	3,766.32	4,273.01	506.69	13.5%
200	30%	43,800	5,786.78	6,425.35	638.57	11.0%
200	45%	65,700	7,120.71	7,843.38	722.67	10.1%
200	60%	87,600	8,454.64	9,261.40	806.76	9.5%
200	75%	109,500	9,788.57	10,679.43	890.86	9.1%
300	15%	32,850	5,387.11	6,119.76	732.65	13.6%
300	30%	65,700	8,417.81	9,348.28	930.47	11.1%
300	45%	98,550	10,418.70	11,475.31	1,056.61	10.1%
300	60%	131,400	12,419.59	13,602.35	1,182.76	9.5%
300	75%	164,250	14,420.49	15,729.39	1,308.90	9.1%
350	15%	38,325	6,197.51	7,043.14	845.63	13.6%
350	30%	76,650	9,733.32	10,809.74	1,076.42	11.1%
350	45%	114,975	12,067.70	13,291.28	1,223.58	10.1%
350	60%	153,300	14,402.07	15,772.83	1,370.76	9.5%
350	75%	191,625	16,736.45	18,254.37	1,517.92	9.1%
400	15%	43,800	7,007.91	7,966.52	958.61	13.7%
400	30%	87,600	11,048.84	12,271.20	1,222.36	11.1%
400	45%	131,400	13,716.69	15,107.25	1,390.56	10.1%
400	60%	175,200	16,384.55	17,943.30	1,558.75	9.5%
400	75%	219,000	19,052.41	20,779.35	1,726.94	9.1%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

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- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
 - 0 - 99 kW = self contained
 - 100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 M Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$) (E) - (D)	% (F) / (D)
101	15%	11,060	1,995.21	2,266.60	271.39	13.6%
101	30%	22,119	2,848.97	3,175.30	326.33	11.5%
101	45%	33,179	3,356.18	3,713.15	356.97	10.6%
101	60%	44,238	3,863.34	4,250.94	387.60	10.0%
101	75%	55,298	4,370.56	4,788.79	418.23	9.6%
150	15%	16,425	2,708.56	3,085.02	376.46	13.9%
150	30%	32,850	3,976.57	4,434.65	458.08	11.5%
150	45%	49,275	4,729.82	5,233.39	503.57	10.6%
150	60%	65,700	5,483.07	6,032.14	549.07	10.0%
150	75%	82,125	6,236.32	6,830.89	594.57	9.5%
200	15%	21,900	3,436.50	3,920.20	483.70	14.1%
200	30%	43,800	5,127.19	5,719.69	592.50	11.6%
200	45%	65,700	6,131.52	6,784.69	653.17	10.7%
200	60%	87,600	7,135.86	7,849.69	713.83	10.0%
200	75%	109,500	8,140.19	8,914.69	774.50	9.5%
300	15%	32,850	4,892.39	5,590.55	698.16	14.3%
300	30%	65,700	7,428.42	8,289.79	861.37	11.6%
300	45%	98,550	8,934.92	9,887.29	952.37	10.7%
300	60%	131,400	10,441.42	11,484.78	1,043.36	10.0%
300	75%	164,250	11,947.93	13,082.28	1,134.35	9.5%
350	15%	38,325	5,620.34	6,425.72	805.38	14.3%
350	30%	76,650	8,579.04	9,574.84	995.80	11.6%
350	45%	114,975	10,336.62	11,438.58	1,101.96	10.7%
350	60%	153,300	12,094.21	13,302.33	1,208.12	10.0%
350	75%	191,625	13,851.79	15,166.07	1,314.28	9.5%
400	15%	43,800	6,348.28	7,260.90	912.62	14.4%
400	30%	87,600	9,729.66	10,859.89	1,130.23	11.6%
400	45%	131,400	11,738.32	12,989.88	1,251.56	10.7%
400	60%	175,200	13,746.99	15,119.88	1,372.89	10.0%
400	75%	219,000	15,755.66	17,249.87	1,494.21	9.5%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
 - 0 - 99 kW = self contained
 - 100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 L Summer (May - October)

(excludes bill reduction from transferring adjutor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)		(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change		
					Amount (\$)	%	
					(E) - (D)	(F) / (D)	
401	15%	43,910	8,880.59	10,386.30	1,505.71	17.0%	
401	30%	87,819	11,303.05	12,818.64	1,515.59	13.4%	
401	45%	131,729	13,725.57	15,251.03	1,525.46	11.1%	
401	60%	175,638	16,148.03	17,683.37	1,535.34	9.5%	
401	75%	219,548	18,570.54	20,115.77	1,545.23	8.3%	
600	15%	65,700	12,921.88	15,096.75	2,174.87	16.8%	
600	30%	131,400	16,546.55	18,736.20	2,189.65	13.2%	
600	45%	197,100	20,171.22	22,375.65	2,204.43	10.9%	
600	60%	262,800	23,795.89	26,015.11	2,219.22	9.3%	
600	75%	328,500	27,420.56	29,654.56	2,234.00	8.1%	
800	15%	87,600	16,983.50	19,830.90	2,847.40	16.8%	
800	30%	175,200	21,816.39	24,683.50	2,867.11	13.1%	
800	45%	262,800	26,649.29	29,536.11	2,886.82	10.8%	
800	60%	350,400	31,482.18	34,388.71	2,906.53	9.2%	
800	75%	438,000	36,315.07	39,241.31	2,926.24	8.1%	
1,000	15%	109,500	21,045.13	24,565.05	3,519.92	16.7%	
1,000	30%	219,000	27,086.24	30,630.81	3,544.57	13.1%	
1,000	45%	328,500	33,127.36	36,696.56	3,569.20	10.8%	
1,000	60%	438,000	39,168.47	42,762.31	3,593.84	9.2%	
1,000	75%	547,500	45,209.59	48,828.06	3,618.47	8.0%	
1,500	15%	164,250	31,199.18	36,400.43	5,201.25	16.7%	
1,500	30%	328,500	40,260.86	45,499.06	5,238.20	13.0%	
1,500	45%	492,750	49,322.53	54,597.69	5,275.16	10.7%	
1,500	60%	657,000	58,384.20	63,696.32	5,312.12	9.1%	
1,500	75%	821,250	67,445.87	72,794.94	5,349.07	7.9%	
3,000	15%	328,500	61,661.36	71,906.56	10,245.20	16.6%	
3,000	30%	657,000	79,784.70	90,103.82	10,319.12	12.9%	
3,000	45%	985,500	97,908.05	108,301.07	10,393.02	10.6%	
3,000	60%	1,314,000	116,031.39	126,498.33	10,466.94	9.0%	
3,000	75%	1,642,500	134,154.74	144,695.59	10,540.85	7.9%	

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32 L Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change		(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%	
					(E) - (D)	(F) / (D)	
401	15%	43,910	8,128.41	9,583.84	1,455.43	17.9%	
401	30%	87,819	9,798.71	11,213.75	1,415.04	14.4%	
401	45%	131,729	11,469.05	12,843.69	1,374.64	12.0%	
401	60%	175,638	13,139.35	14,473.59	1,334.24	10.2%	
401	75%	219,548	14,809.68	16,103.53	1,293.85	8.7%	
600	15%	65,700	11,796.44	13,896.08	2,099.64	17.8%	
600	30%	131,400	14,295.67	16,334.87	2,039.20	14.3%	
600	45%	197,100	16,794.89	18,773.65	1,978.76	11.8%	
600	60%	262,800	19,294.12	21,212.44	1,918.32	9.9%	
600	75%	328,500	21,793.35	23,651.22	1,857.87	8.5%	
800	15%	87,600	15,482.91	18,230.01	2,747.10	17.7%	
800	30%	175,200	18,815.22	21,481.72	2,666.50	14.2%	
800	45%	262,800	22,147.52	24,733.44	2,585.92	11.7%	
800	60%	350,400	25,479.83	27,985.15	2,505.32	9.8%	
800	75%	438,000	28,812.13	31,236.86	2,424.73	8.4%	
1,000	15%	109,500	19,169.39	22,563.94	3,394.55	17.7%	
1,000	30%	219,000	23,334.77	26,628.58	3,293.81	14.1%	
1,000	45%	328,500	27,500.15	30,693.22	3,193.07	11.6%	
1,000	60%	438,000	31,665.53	34,757.86	3,092.33	9.8%	
1,000	75%	547,500	35,830.91	38,822.50	2,991.59	8.3%	
1,500	15%	164,250	28,385.58	33,398.76	5,013.18	17.7%	
1,500	30%	328,500	34,633.65	39,495.72	4,862.07	14.0%	
1,500	45%	492,750	40,881.72	45,592.68	4,710.96	11.5%	
1,500	60%	657,000	47,129.79	51,689.64	4,559.85	9.7%	
1,500	75%	821,250	53,377.86	57,786.60	4,408.74	8.3%	
3,000	15%	328,500	56,034.15	65,903.22	9,869.07	17.6%	
3,000	30%	657,000	68,530.29	78,097.14	9,566.85	14.0%	
3,000	45%	985,500	81,026.43	90,291.06	9,264.63	11.4%	
3,000	60%	1,314,000	93,522.57	102,484.98	8,962.41	9.6%	
3,000	75%	1,642,500	106,018.71	114,678.90	8,660.19	8.2%	

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
 - 0 - 99 kW = self contained
 - 100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU XS Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On- Peak kW	Off- Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount (\$)	%
						(F) - (E)	(G) / (E)
5	7.5	15%	821	138.30	174.26	35.96	26.0%
5	7.5	30%	1,643	255.44	271.61	16.17	6.3%
5	7.5	45%	2,464	372.44	368.84	(3.60)	-1.0%
5	7.5	60%	3,285	489.44	466.07	(23.37)	-4.8%
5	7.5	75%	4,106	606.44	563.31	(43.13)	-7.1%
10	12	15%	1,314	208.56	267.07	58.51	28.1%
10	12	30%	2,628	395.81	422.69	26.88	6.8%
10	12	45%	3,942	583.07	578.31	(4.76)	-0.8%
10	12	60%	5,256	770.33	733.93	(36.40)	-4.7%
10	12	75%	6,570	957.59	889.55	(68.04)	-7.1%
15	20	15%	2,190	333.40	414.34	80.94	24.3%
15	20	30%	4,380	645.49	673.71	28.22	4.4%
15	20	45%	6,570	957.59	933.07	(24.52)	-2.6%
15	20	60%	8,760	1,221.59	1,192.44	(29.15)	-2.4%
15	20	75%	10,950	1,422.52	1,451.81	29.29	2.1%
20	25	15%	2,738	411.49	514.96	103.47	25.1%
20	25	30%	5,475	801.54	839.11	37.57	4.7%
20	25	45%	8,213	1,171.40	1,163.38	(8.02)	-0.7%
20	25	60%	10,950	1,422.52	1,487.53	65.01	4.6%
20	25	75%	13,688	1,673.73	1,811.80	138.07	8.2%

General Service TOU Average Energy On-Peak: 36%
Proposed General Service TOU Average Energy On-Peak: 13%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
 - 0 - 99 kW = self contained
 - 100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU XS Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount (\$)	%
						(F) - (E)	(G) / (E)
5	7.5	15%	821	122.70	154.63	31.93	26.0%
5	7.5	30%	1,643	224.23	232.32	8.09	3.6%
5	7.5	45%	2,464	325.64	309.93	(15.71)	-4.8%
5	7.5	60%	3,285	427.04	387.53	(39.51)	-9.3%
5	7.5	75%	4,106	528.45	465.13	(63.32)	-12.0%
10	12	15%	1,314	183.60	235.65	52.05	28.3%
10	12	30%	2,628	345.89	359.85	13.96	4.0%
10	12	45%	3,942	508.19	484.06	(24.13)	-4.7%
10	12	60%	5,256	670.49	608.26	(62.23)	-9.3%
10	12	75%	6,570	832.78	732.46	(100.32)	-12.0%
15	20	15%	2,190	291.79	361.97	70.18	24.1%
15	20	30%	4,380	562.29	568.98	6.69	1.2%
15	20	45%	6,570	832.78	775.98	(56.80)	-6.8%
15	20	60%	8,760	1,031.87	982.99	(48.88)	-4.7%
15	20	75%	10,950	1,191.22	1,189.99	(1.23)	-0.1%
20	25	15%	2,738	359.48	449.50	90.02	25.0%
20	25	30%	5,475	697.53	708.21	10.68	1.5%
20	25	45%	8,213	992.07	967.01	(25.06)	-2.5%
20	25	60%	10,950	1,191.22	1,225.72	34.50	2.9%
20	25	75%	13,688	1,390.45	1,484.52	94.07	6.8%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 13%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU S Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount (\$)	%
						(F) - (E)	(G) / (E)
21	30	15%	3,285	694.82	811.20	116.38	16.7%
21	30	30%	6,570	903.45	998.84	95.39	10.6%
21	30	45%	9,855	1,112.08	1,186.48	74.40	6.7%
21	30	60%	13,140	1,320.71	1,374.12	53.41	4.0%
21	30	75%	16,425	1,529.35	1,561.76	32.41	2.1%
40	50	15%	5,475	1,215.34	1,412.71	197.37	16.2%
40	50	30%	10,950	1,563.06	1,725.44	162.38	10.4%
40	50	45%	16,425	1,910.78	2,038.17	127.39	6.7%
40	50	60%	21,900	2,258.51	2,350.91	92.40	4.1%
40	50	75%	27,375	2,606.23	2,663.64	57.41	2.2%
60	70	15%	7,665	1,750.17	2,031.00	280.83	16.0%
60	70	30%	15,330	2,236.98	2,468.82	231.84	10.4%
60	70	45%	22,995	2,723.79	2,906.65	182.86	6.7%
60	70	60%	30,660	3,210.60	3,344.47	133.87	4.2%
60	70	75%	38,325	3,697.41	3,782.29	84.88	2.3%
80	100	15%	10,950	2,409.38	2,790.62	381.24	15.8%
80	100	30%	21,900	3,104.83	3,416.08	311.25	10.0%
80	100	45%	32,850	3,800.27	4,041.55	241.28	6.3%
80	100	60%	43,800	4,495.71	4,667.01	171.30	3.8%
80	100	75%	54,750	5,191.16	5,292.47	101.31	2.0%
90	110	15%	12,045	2,652.50	3,048.12	395.62	14.9%
90	110	30%	24,090	3,417.49	3,736.13	318.64	9.3%
90	110	45%	36,135	4,182.47	4,424.14	241.67	5.8%
90	110	60%	48,180	4,947.46	5,112.15	164.69	3.3%
90	110	75%	60,225	5,712.45	5,800.16	87.71	1.5%
100	120	15%	13,140	2,895.61	3,305.62	410.01	14.2%
100	120	30%	26,280	3,730.14	4,056.18	326.04	8.7%
100	120	45%	39,420	4,564.68	4,806.74	242.06	5.3%
100	120	60%	52,560	5,399.21	5,557.30	158.09	2.9%
100	120	75%	65,700	6,233.74	6,307.85	74.11	1.2%

General Service TOU Average Energy On-Peak:	32%
Proposed General Service TOU Average Energy On-Peak:	16%
Proposed General Service TOU Estimated Demand Reduction On-Peak:	16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

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- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
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100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU S Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
						(F) - (E)	(G) / (E)
21	30	15%	3,285	638.88	808.67	169.79	26.6%
21	30	30%	6,570	791.58	951.82	160.24	20.2%
21	30	45%	9,855	944.28	1,094.98	150.70	16.0%
21	30	60%	13,140	1,096.98	1,238.13	141.15	12.9%
21	30	75%	16,425	1,249.68	1,381.28	131.60	10.5%
40	50	15%	5,475	1,122.12	1,418.47	296.35	26.4%
40	50	30%	10,950	1,376.62	1,657.06	280.44	20.4%
40	50	45%	16,425	1,631.12	1,895.65	264.53	16.2%
40	50	60%	21,900	1,885.62	2,134.24	248.62	13.2%
40	50	75%	27,375	2,140.12	2,372.83	232.71	10.9%
60	70	15%	7,665	1,619.66	2,047.06	427.40	26.4%
60	70	30%	15,330	1,975.96	2,381.08	405.12	20.5%
60	70	45%	22,995	2,332.26	2,715.11	382.85	16.4%
60	70	60%	30,660	2,688.56	3,049.13	360.57	13.4%
60	70	75%	38,325	3,044.86	3,383.16	338.30	11.1%
80	100	15%	10,950	2,222.94	2,802.15	579.21	26.1%
80	100	30%	21,900	2,731.94	3,279.33	547.39	20.0%
80	100	45%	32,850	3,240.94	3,756.51	515.57	15.9%
80	100	60%	43,800	3,749.94	4,233.69	483.75	12.9%
80	100	75%	54,750	4,258.94	4,710.87	451.93	10.6%
90	110	15%	12,045	2,447.41	3,064.80	617.39	25.2%
90	110	30%	24,090	3,007.31	3,589.70	582.39	19.4%
90	110	45%	36,135	3,567.21	4,114.60	547.39	15.3%
90	110	60%	48,180	4,127.11	4,639.49	512.38	12.4%
90	110	75%	60,225	4,687.01	5,164.39	477.38	10.2%
100	120	15%	13,140	2,671.88	3,327.45	655.57	24.5%
100	120	30%	26,280	3,282.68	3,900.07	617.39	18.8%
100	120	45%	39,420	3,893.48	4,472.68	579.20	14.9%
100	120	60%	52,560	4,504.28	5,045.30	541.02	12.0%
100	120	75%	65,700	5,115.08	5,617.91	502.83	9.8%

General Service TOU Average Energy On-Peak:	32%
Proposed General Service TOU Average Energy On-Peak:	16%
Proposed General Service TOU Estimated Demand Reduction On-Peak:	6%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
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- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
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Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU M Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On- Peak kW	Off- Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount (\$)	%
						(F) - (E)	(G) / (E)
101	120	15%	13,140	2,980.84	3,391.11	410.27	13.8%
101	120	30%	26,280	3,742.29	4,198.81	456.52	12.2%
101	120	45%	39,420	4,503.73	5,006.51	502.78	11.2%
101	120	60%	52,560	5,265.18	5,814.21	549.03	10.4%
101	120	75%	65,700	6,026.63	6,621.91	595.28	9.9%
150	170	15%	18,615	3,947.15	4,465.28	518.13	13.1%
150	170	30%	37,230	5,025.86	5,609.53	583.67	11.6%
150	170	45%	55,845	6,104.58	6,753.77	649.19	10.6%
150	170	60%	74,460	7,183.30	7,898.01	714.71	9.9%
150	170	75%	93,075	8,262.01	9,042.25	780.24	9.4%
200	220	15%	24,090	4,923.47	5,537.76	614.29	12.5%
200	220	30%	48,180	6,319.45	7,018.54	699.09	11.1%
200	220	45%	72,270	7,715.44	8,499.33	783.89	10.2%
200	220	60%	96,360	9,111.43	9,980.11	868.68	9.5%
200	220	75%	120,450	10,507.41	11,460.89	953.48	9.1%
300	320	15%	35,040	6,876.11	7,682.71	806.60	11.7%
300	320	30%	70,080	8,906.63	9,836.58	929.95	10.4%
300	320	45%	105,120	10,937.16	11,990.44	1,053.28	9.6%
300	320	60%	140,160	12,967.68	14,144.31	1,176.63	9.1%
300	320	75%	175,200	14,998.21	16,298.18	1,299.97	8.7%
350	370	15%	40,515	7,852.43	8,755.19	902.76	11.5%
350	370	30%	81,030	10,200.22	11,245.59	1,045.37	10.2%
350	370	45%	121,545	12,548.02	13,736.00	1,187.98	9.5%
350	370	60%	162,060	14,895.81	16,226.41	1,330.60	8.9%
350	370	75%	202,575	17,243.61	18,716.82	1,473.21	8.5%
400	420	15%	45,990	8,828.75	9,827.66	998.91	11.3%
400	420	30%	91,980	11,493.81	12,654.61	1,160.80	10.1%
400	420	45%	137,970	14,158.88	15,481.56	1,322.68	9.3%
400	420	60%	183,960	16,823.94	18,308.51	1,484.57	8.8%
400	420	75%	229,950	19,489.01	21,135.46	1,646.45	8.4%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 16%
Proposed General Service TOU Estimated Demand Reduction On-Peak: 3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU M Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)		(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change		
						Amount (\$)	%	
						(F) - (E)	(G) / (E)	
101	120	15%	13,140	2,811.29	3,208.97	397.68	14.1%	
101	120	30%	26,280	3,403.19	3,834.53	431.34	12.7%	
101	120	45%	39,420	3,995.09	4,460.09	465.00	11.6%	
101	120	60%	52,560	4,586.99	5,085.65	498.66	10.9%	
101	120	75%	65,700	5,178.89	5,711.21	532.32	10.3%	
150	170	15%	18,615	3,706.95	4,207.25	500.30	13.5%	
150	170	30%	37,230	4,545.48	5,093.46	547.98	12.1%	
150	170	45%	55,845	5,384.00	5,979.67	595.67	11.1%	
150	170	60%	74,460	6,222.53	6,865.87	643.34	10.3%	
150	170	75%	93,075	7,061.05	7,752.08	691.03	9.8%	
200	220	15%	24,090	4,612.63	5,203.83	591.20	12.8%	
200	220	30%	48,180	5,697.78	6,350.69	652.91	11.5%	
200	220	45%	72,270	6,782.93	7,497.55	714.62	10.5%	
200	220	60%	96,360	7,868.07	8,644.41	776.34	9.9%	
200	220	75%	120,450	8,953.22	9,791.26	838.04	9.4%	
300	320	15%	35,040	6,423.98	7,197.00	773.02	12.0%	
300	320	30%	70,080	8,002.38	8,865.16	862.78	10.8%	
300	320	45%	105,120	9,580.77	10,533.31	952.54	9.9%	
300	320	60%	140,160	11,159.17	12,201.47	1,042.30	9.3%	
300	320	75%	175,200	12,737.57	13,869.63	1,132.06	8.9%	
350	370	15%	40,515	7,329.65	8,193.58	863.93	11.8%	
350	370	30%	81,030	9,154.67	10,122.39	967.72	10.6%	
350	370	45%	121,545	10,979.70	12,051.20	1,071.50	9.8%	
350	370	60%	162,060	12,804.72	13,980.00	1,175.28	9.2%	
350	370	75%	202,575	14,629.74	15,908.81	1,279.07	8.7%	
400	420	15%	45,990	8,235.33	9,190.17	954.84	11.6%	
400	420	30%	91,980	10,306.97	11,379.62	1,072.65	10.4%	
400	420	45%	137,970	12,378.62	13,569.08	1,190.46	9.6%	
400	420	60%	183,960	14,450.27	15,758.53	1,308.26	9.1%	
400	420	75%	229,950	16,521.92	17,947.99	1,426.07	8.6%	

General Service TOU Average Energy On-Peak:	32%
Proposed General Service TOU Average Energy On-Peak:	16%
Proposed General Service TOU Estimated Demand Reduction On-Peak:	3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU L Summer (May - October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	Change	
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
						(F) - (E)	(G) / (E)
401	441	15%	48,290	8,886.36	10,074.00	1,187.64	13.4%
401	441	30%	96,579	11,658.98	12,940.47	1,281.49	11.0%
401	441	45%	144,869	14,431.65	15,807.00	1,375.35	9.5%
401	441	60%	193,158	17,204.27	18,673.48	1,469.21	8.5%
401	441	75%	241,448	19,976.95	21,540.01	1,563.06	7.8%
600	640	15%	70,080	12,700.80	14,385.30	1,684.50	13.3%
600	640	30%	140,160	16,724.59	18,545.31	1,820.72	10.9%
600	640	45%	210,240	20,748.39	22,705.31	1,956.92	9.4%
600	640	60%	280,320	24,772.19	26,865.32	2,093.13	8.4%
600	640	75%	350,400	28,795.99	31,025.32	2,229.33	7.7%
800	860	15%	94,170	16,722.12	18,915.71	2,193.59	13.1%
800	860	30%	188,340	22,129.10	24,505.71	2,376.61	10.7%
800	860	45%	282,510	27,536.07	30,095.72	2,559.65	9.3%
800	860	60%	376,680	32,943.05	35,685.73	2,742.68	8.3%
800	860	75%	470,850	38,350.03	41,275.73	2,925.70	7.6%
1,000	1,200	15%	131,400	21,869.54	24,630.51	2,760.97	12.6%
1,000	1,200	30%	262,800	29,414.16	32,430.52	3,016.36	10.3%
1,000	1,200	45%	394,200	36,958.78	40,230.53	3,271.75	8.9%
1,000	1,200	60%	525,600	44,503.40	48,030.54	3,527.14	7.9%
1,000	1,200	75%	657,000	52,048.02	55,830.55	3,782.53	7.3%
1,500	1,700	15%	186,150	31,453.63	35,463.01	4,009.38	12.7%
1,500	1,700	30%	372,300	42,141.84	46,513.03	4,371.19	10.4%
1,500	1,700	45%	558,450	52,830.06	57,563.04	4,732.98	9.0%
1,500	1,700	60%	744,600	63,518.27	68,613.05	5,094.78	8.0%
1,500	1,700	75%	930,750	74,206.48	79,663.06	5,456.58	7.4%
3,000	3,200	15%	350,400	60,205.91	67,960.52	7,754.61	12.9%
3,000	3,200	30%	700,800	80,324.89	88,760.55	8,435.66	10.5%
3,000	3,200	45%	1,051,200	100,443.88	109,560.57	9,116.69	9.1%
3,000	3,200	60%	1,401,600	120,562.87	130,360.60	9,797.73	8.1%
3,000	3,200	75%	1,752,000	140,681.85	151,160.62	10,478.77	7.4%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-32TOU L Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount (\$) (F) - (E)	% (G) / (E)
401	441	15%	48,290	8,228.65	9,366.07	1,137.42	13.8%
401	441	30%	96,579	10,343.57	11,524.62	1,181.05	11.4%
401	441	45%	144,869	12,458.54	13,683.23	1,224.69	9.8%
401	441	60%	193,158	14,573.46	15,841.78	1,268.32	8.7%
401	441	75%	241,448	16,688.43	18,000.38	1,311.95	7.9%
600	640	15%	70,080	11,746.31	13,357.93	1,611.62	13.7%
600	640	30%	140,160	14,815.62	16,490.56	1,674.94	11.3%
600	640	45%	210,240	17,884.92	19,623.20	1,738.28	9.7%
600	640	60%	280,320	20,954.23	22,755.83	1,801.60	8.6%
600	640	75%	350,400	24,023.54	25,888.46	1,864.92	7.8%
800	860	15%	94,170	15,439.52	17,535.17	2,095.65	13.6%
800	860	30%	188,340	19,563.90	21,744.65	2,180.75	11.1%
800	860	45%	282,510	23,688.29	25,954.12	2,265.83	9.6%
800	860	60%	376,680	27,812.67	30,163.60	2,350.93	8.5%
800	860	75%	470,850	31,937.05	34,373.07	2,436.02	7.6%
1,000	1,200	15%	131,400	20,079.87	22,704.19	2,624.32	13.1%
1,000	1,200	30%	262,800	25,834.82	28,577.87	2,743.05	10.6%
1,000	1,200	45%	394,200	31,589.78	34,451.56	2,861.78	9.1%
1,000	1,200	60%	525,600	37,344.73	40,325.24	2,980.51	8.0%
1,000	1,200	75%	657,000	43,099.68	46,198.93	3,099.25	7.2%
1,500	1,700	15%	186,150	28,918.27	32,734.05	3,815.78	13.2%
1,500	1,700	30%	372,300	37,071.12	41,055.11	3,983.99	10.7%
1,500	1,700	45%	558,450	45,223.97	49,376.16	4,152.19	9.2%
1,500	1,700	60%	744,600	53,376.82	57,697.22	4,320.40	8.1%
1,500	1,700	75%	930,750	61,529.66	66,018.27	4,488.61	7.3%
3,000	3,200	15%	350,400	55,433.46	62,823.66	7,390.20	13.3%
3,000	3,200	30%	700,800	70,780.00	78,486.82	7,706.82	10.9%
3,000	3,200	45%	1,051,200	86,126.54	94,149.98	8,023.44	9.3%
3,000	3,200	60%	1,401,600	101,473.08	109,813.14	8,340.06	8.2%
3,000	3,200	75%	1,752,000	116,819.61	125,476.30	8,656.69	7.4%

General Service TOU Average Energy On-Peak: 32%
Proposed General Service TOU Average Energy On-Peak: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-34

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$) (E) - (D)	% (F) / (D)
3,000	20%	438,000	75,895.98	83,578.02	7,682.04	10.1%
3,000	30%	657,000	83,922.33	92,276.70	8,354.37	10.0%
3,000	40%	876,000	91,948.68	100,975.38	9,026.70	9.8%
3,000	50%	1,095,000	99,975.03	109,674.06	9,699.03	9.7%
3,000	75%	1,642,500	120,040.91	131,420.76	11,379.85	9.5%
3,500	20%	511,000	88,536.43	97,482.08	8,945.65	10.1%
3,500	30%	766,500	97,900.51	107,630.54	9,730.03	9.9%
3,500	40%	1,022,000	107,264.58	117,779.00	10,514.42	9.8%
3,500	50%	1,277,500	116,628.66	127,927.46	11,298.80	9.7%
3,500	75%	1,916,250	140,038.84	153,298.61	13,259.77	9.5%
4,000	20%	584,000	101,176.88	111,386.14	10,209.26	10.1%
4,000	30%	876,000	111,878.68	122,984.38	11,105.70	9.9%
4,000	40%	1,168,000	122,580.48	134,582.62	12,002.14	9.8%
4,000	50%	1,460,000	133,282.28	146,180.86	12,898.58	9.7%
4,000	75%	2,190,000	160,036.78	175,176.46	15,139.68	9.5%
4,500	20%	657,000	113,817.33	125,290.20	11,472.87	10.1%
4,500	30%	985,500	125,856.86	138,338.22	12,481.36	9.9%
4,500	40%	1,314,000	137,896.38	151,386.24	13,489.86	9.8%
4,500	50%	1,642,500	149,935.91	164,434.26	14,498.35	9.7%
4,500	75%	2,463,750	180,034.72	197,054.31	17,019.59	9.5%
5,000	20%	730,000	126,457.78	139,194.26	12,736.48	10.1%
5,000	30%	1,095,000	139,835.03	153,692.06	13,857.03	9.9%
5,000	40%	1,460,000	153,212.28	168,189.86	14,977.58	9.8%
5,000	50%	1,825,000	166,589.53	182,687.66	16,098.13	9.7%
5,000	75%	2,737,500	200,032.66	218,932.16	18,899.50	9.4%
6,000	20%	876,000	151,738.68	167,002.38	15,263.70	10.1%
6,000	30%	1,314,000	167,791.38	184,399.74	16,608.36	9.9%
6,000	40%	1,752,000	183,844.08	201,797.10	17,953.02	9.8%
6,000	50%	2,190,000	199,896.78	219,194.46	19,297.68	9.7%
6,000	75%	3,285,000	240,028.53	262,687.86	22,659.33	9.4%
7,000	20%	1,022,000	177,019.58	194,810.50	17,790.92	10.1%
7,000	30%	1,533,000	195,747.73	215,107.42	19,359.69	9.9%
7,000	50%	2,555,000	233,204.03	255,701.26	22,497.23	9.6%
7,000	75%	3,832,500	280,024.41	306,443.56	26,419.15	9.4%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-35

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount (\$)	%
						(F) - (E)	(G) / (E)
3,000	4,000	20%	438,000	77,839.17	86,515.62	8,676.45	11.1%
3,000	4,000	30%	657,000	85,451.83	94,903.10	9,451.27	11.1%
3,000	4,000	40%	876,000	93,064.49	103,290.58	10,226.09	11.0%
3,000	4,000	50%	1,095,000	100,677.15	111,678.07	11,000.92	10.9%
3,000	4,000	75%	1,642,500	119,708.79	132,646.77	12,937.98	10.8%
3,500	4,500	20%	511,000	90,292.72	100,413.45	10,120.73	11.2%
3,500	4,500	30%	766,500	99,174.16	110,198.84	11,024.68	11.1%
3,500	4,500	40%	1,022,000	108,055.59	119,984.24	11,928.65	11.0%
3,500	4,500	50%	1,277,500	116,937.03	129,769.63	12,832.60	11.0%
3,500	4,500	75%	1,916,250	139,140.62	154,233.12	15,092.50	10.8%
4,000	5,000	20%	584,000	102,746.27	114,311.28	11,565.01	11.3%
4,000	5,000	30%	876,000	112,896.49	125,494.58	12,598.09	11.2%
4,000	5,000	40%	1,168,000	123,046.70	136,677.89	13,631.19	11.1%
4,000	5,000	50%	1,460,000	133,196.91	147,861.20	14,664.29	11.0%
4,000	5,000	75%	2,190,000	158,572.44	175,819.47	17,247.03	10.9%
4,500	6,000	20%	657,000	116,731.83	129,696.60	12,964.77	11.1%
4,500	6,000	30%	985,500	128,150.82	142,277.82	14,127.00	11.0%
4,500	6,000	40%	1,314,000	139,569.80	154,859.05	15,289.25	11.0%
4,500	6,000	50%	1,642,500	150,988.79	167,440.27	16,451.48	10.9%
4,500	6,000	75%	2,463,750	179,536.26	198,893.32	19,357.06	10.8%
5,000	7,000	20%	730,000	130,717.38	145,081.93	14,364.55	11.0%
5,000	7,000	30%	1,095,000	143,405.15	159,061.07	15,655.92	10.9%
5,000	7,000	40%	1,460,000	156,092.91	173,040.20	16,947.29	10.9%
5,000	7,000	50%	1,825,000	168,780.68	187,019.34	18,238.66	10.8%
5,000	7,000	75%	2,737,500	200,500.09	221,967.17	21,467.08	10.7%
6,000	8,000	20%	876,000	155,624.49	172,877.58	17,253.09	11.1%
6,000	8,000	30%	1,314,000	170,849.80	189,652.55	18,802.75	11.0%
6,000	8,000	40%	1,752,000	186,075.12	206,427.51	20,352.39	10.9%
6,000	8,000	50%	2,190,000	201,300.44	223,202.47	21,902.03	10.9%
6,000	8,000	75%	3,285,000	239,363.74	265,139.88	25,776.14	10.8%
7,000	8,500	20%	1,022,000	178,999.59	199,185.74	20,186.15	11.3%
7,000	8,500	30%	1,533,000	196,762.46	218,756.53	21,994.07	11.2%
7,000	8,500	40%	2,044,000	214,525.33	238,327.32	23,801.99	11.1%
7,000	8,500	50%	2,555,000	232,288.21	257,898.11	25,609.90	11.0%
7,000	8,500	75%	3,832,500	276,695.38	306,825.08	30,129.70	10.9%

E-35 Average Energy On-Peak: 30%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-47

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Type of Fixture	Lumen	Monthly kWh	Ownership	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount (\$)	%
						(F) - (E)	(G) / (E)
HPS, cobra / roadway	5,800	29	Company	8.73	9.40	0.67	7.7%
		29	Customer	5.16	5.56	0.40	7.8%
HPS, cobra / roadway	9,500	41	Company	10.28	11.07	0.79	7.7%
		41	Customer	6.32	6.81	0.49	7.8%
HPS, architectural	9,500	41	Company	15.38	16.56	1.18	7.7%
		41	Customer	7.34	7.90	0.56	7.6%
HPS, acom luminaire	9,500	41	Company	27.06	29.14	2.08	7.7%
		41	Customer	9.22	9.93	0.71	7.7%
HPS, cobra / roadway	16,000	69	Company	12.87	13.86	0.99	7.7%
		69	Customer	8.82	9.50	0.68	7.7%
HPS, architectural	16,000	69	Company	17.96	19.34	1.38	7.7%
		69	Customer	9.82	10.58	0.76	7.7%
HPS, acom luminaire	16,000	69	Company	30.04	32.35	2.31	7.7%
		69	Customer	11.65	12.55	0.90	7.7%
HPS, cobra / roadway	30,000	99	Company	15.52	16.72	1.20	7.7%
		99	Customer	11.46	12.35	0.89	7.8%
HPS, architectural	30,000	99	Company	21.31	22.95	1.64	7.7%
		99	Customer	12.60	13.57	0.97	7.7%
HPS, cobra / roadway	50,000	153	Company	21.06	22.69	1.63	7.7%
		153	Customer	16.37	17.63	1.26	7.7%
HPS, architectural	50,000	153	Company	26.29	28.32	2.03	7.7%
		153	Customer	18.13	19.53	1.40	7.7%
LPS, architectural	8,000	30	Company	22.35	24.08	1.73	7.7%
		30	Customer	9.82	10.58	0.76	7.7%
LPS, architectural	13,500	50	Company	26.36	28.39	2.03	7.7%
LPS, architectural	22,500	72	Company	30.11	32.43	2.32	7.7%
		72	Customer	14.45	15.56	1.11	7.7%
LPS, architectural	33,000	90	Company	36.22	39.01	2.79	7.7%
		90	Customer	17.02	18.33	1.31	7.7%
Type of Pole	Height	Desc.					
Direct Bury	30 FT	Round Steel	Company	14.38	15.49	1.11	7.7%
			Customer	N/A			N/A
Direct Bury	34 FT	Square Steel	Company	15.87	17.09	1.22	7.7%
			Customer	N/A	N/A		N/A

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-58

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
Type of Fixture	Lumen	Monthly kWh	Ownership	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
						Amount (\$) (F) - (E)	% (G) / (E)
HPS, cobra / roadway	5,800	29	Company	8.73	9.40	0.67	7.7%
		29	Customer	5.16	5.56	0.40	7.8%
HPS, cobra / roadway	9,500	41	Company	10.28	11.07	0.79	7.7%
		41	Customer	6.32	6.81	0.49	7.8%
HPS, architectural	9,500	41	Company	15.38	16.56	1.18	7.7%
		41	Customer	7.34	7.90	0.56	7.6%
HPS, acorn luminaire	9,500	41	Company	27.06	29.14	2.08	7.7%
		41	Customer	9.22	9.93	0.71	7.7%
HPS, cobra / roadway	16,000	69	Company	12.87	13.86	0.99	7.7%
		69	Customer	8.82	9.50	0.68	7.7%
HPS, architectural	16,000	69	Company	17.96	19.34	1.38	7.7%
		69	Customer	9.82	10.58	0.76	7.7%
HPS, acorn luminaire	16,000	69	Company	30.04	32.35	2.31	7.7%
		69	Customer	11.65	12.55	0.90	7.7%
HPS, cobra / roadway	30,000	99	Company	15.52	16.72	1.20	7.7%
		99	Customer	11.46	12.35	0.89	7.8%
HPS, architectural	30,000	99	Company	21.31	22.95	1.64	7.7%
		99	Customer	12.60	13.57	0.97	7.7%
HPS, cobra / roadway	50,000	153	Company	21.06	22.69	1.63	7.7%
		153	Customer	16.37	17.63	1.26	7.7%
HPS, architectural	50,000	153	Company	26.29	28.32	2.03	7.7%
		153	Customer	18.13	19.53	1.40	7.7%
LPS, architectural	8,000	30	Company	22.35	24.08	1.73	7.7%
		30	Customer	9.82	10.58	0.76	7.7%
LPS, architectural	13,500	50	Company	26.36	28.39	2.03	7.7%
LPS, architectural	22,500	72	Company	30.11	32.43	2.32	7.7%
		72	Customer	14.45	15.56	1.11	7.7%
LPS, architectural	33,000	90	Company	36.22	39.01	2.79	7.7%
		90	Customer	17.02	18.33	1.31	7.7%
Type of Pole	Height	Desc.					
Direct Bury	30 FT	Round	Company	14.38	15.49	1.11	7.7%
		Steel	Customer	2.66	2.87	0.21	7.9%
Direct Bury	34 FT	Square	Company	15.87	17.09	1.22	7.7%
		Steel	Customer	2.75	2.96	0.21	7.6%
Direct Bury	38 FT	Square	Company	17.05	18.36	1.31	7.7%
		Steel	Customer	2.96	3.19	0.23	7.8%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-59

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)
Lamps	kWh per Lamp	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change Amount (\$) (E) - (D)	% (F) / (D)
50	30	1,500	230.82	248.45	17.63	7.6%
50	60	3,000	322.14	346.89	24.75	7.7%
50	75	3,750	367.80	396.11	28.31	7.7%
50	100	5,000	443.90	478.15	34.25	7.7%
50	150	7,500	596.10	642.23	46.13	7.7%
100	30	3,000	461.64	496.89	35.25	7.6%
100	60	6,000	644.28	693.78	49.50	7.7%
100	75	7,500	735.60	792.23	56.63	7.7%
100	100	10,000	887.80	956.30	68.50	7.7%
100	150	15,000	1,192.20	1,284.45	92.25	7.7%
200	30	6,000	923.28	993.78	70.50	7.6%
200	60	12,000	1,288.56	1,387.56	99.00	7.7%
200	75	15,000	1,471.20	1,584.45	113.25	7.7%
200	100	20,000	1,775.60	1,912.60	137.00	7.7%
200	150	30,000	2,384.40	2,568.90	184.50	7.7%
500	30	15,000	2,308.20	2,484.45	176.25	7.6%
500	60	30,000	3,221.40	3,468.90	247.50	7.7%
500	75	37,500	3,678.00	3,961.13	283.13	7.7%
500	100	50,000	4,439.00	4,781.50	342.50	7.7%
500	150	75,000	5,961.00	6,422.25	461.25	7.7%
1,000	30	30,000	4,616.40	4,968.90	352.50	7.6%
1,000	60	60,000	6,442.80	6,937.80	495.00	7.7%
1,000	75	75,000	7,356.00	7,922.25	566.25	7.7%
1,000	100	100,000	8,878.00	9,563.00	685.00	7.7%
1,000	150	150,000	11,922.00	12,844.50	922.50	7.7%
2,000	30	60,000	9,232.80	9,937.80	705.00	7.6%
2,000	60	120,000	12,885.60	13,875.60	990.00	7.7%
2,000	75	150,000	14,712.00	15,844.50	1,132.50	7.7%
2,000	100	200,000	17,756.00	19,126.00	1,370.00	7.7%
2,000	150	300,000	23,844.00	25,689.00	1,845.00	7.7%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-67

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)
Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change	
			Amount (\$)	%
			(C) - (B)	(D) / (B)
30	1.56	1.68	0.12	7.7%
40	2.08	2.24	0.16	7.7%
50	2.60	2.80	0.20	7.7%
60	3.12	3.36	0.24	7.7%
70	3.64	3.92	0.28	7.7%
80	4.15	4.48	0.33	8.0%
90	4.67	5.03	0.36	7.7%
100	5.19	5.59	0.40	7.7%
125	6.49	6.99	0.50	7.7%
150	7.79	8.39	0.60	7.7%
175	9.09	9.79	0.70	7.7%
200	10.39	11.19	0.80	7.7%
225	11.68	12.59	0.91	7.8%
250	12.98	13.99	1.01	7.8%
275	14.28	15.38	1.10	7.7%
300	15.58	16.78	1.20	7.7%
325	16.88	18.18	1.30	7.7%
350	18.18	19.58	1.40	7.7%
375	19.47	20.98	1.51	7.8%
400	20.77	22.38	1.61	7.8%
425	22.07	23.77	1.70	7.7%
450	23.37	25.17	1.80	7.7%
475	24.67	26.57	1.90	7.7%
500	25.97	27.97	2.00	7.7%
600	31.16	33.56	2.40	7.7%
700	36.35	39.16	2.81	7.7%
800	41.54	44.75	3.21	7.7%
900	46.74	50.35	3.61	7.7%
1,000	51.93	55.94	4.01	7.7%
1,500	77.90	83.91	6.01	7.7%
2,000	103.86	111.88	8.02	7.7%
2,500	129.83	139.85	10.02	7.7%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-221

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
					(E) - (D)	(F) / (D)
10	20%	1,460	160.38	197.38	37.00	23.1%
10	35%	2,555	243.96	277.70	33.74	13.8%
10	50%	3,650	318.55	309.62	(8.93)	-2.8%
10	65%	4,745	387.20	309.62	(77.59)	-20.0%
10	80%	5,840	455.86	309.62	(146.24)	-32.1%
30	20%	4,380	430.40	506.67	76.26	17.7%
30	35%	7,665	681.15	747.65	66.51	9.8%
30	50%	10,950	898.36	808.18	(90.19)	-10.0%
30	65%	14,235	1,104.33	808.18	(296.16)	-26.8%
30	80%	17,520	1,310.30	808.18	(502.12)	-38.3%
75	20%	10,950	1,037.96	1,202.57	164.62	15.9%
75	35%	19,163	1,664.85	1,805.08	140.22	8.4%
75	50%	27,375	2,202.95	1,929.94	(273.01)	-12.4%
75	65%	35,588	2,717.90	1,929.94	(787.96)	-29.0%
75	80%	43,800	3,232.79	1,929.94	(1,302.86)	-40.3%
100	20%	14,600	1,375.49	1,589.19	213.70	15.5%
100	35%	25,550	2,211.30	2,392.48	181.18	8.2%
100	50%	36,500	2,927.71	2,553.14	(374.58)	-12.8%
100	65%	47,450	3,614.28	2,553.14	(1,061.14)	-29.4%
100	80%	58,400	4,300.84	2,553.14	(1,747.71)	-40.6%
150	20%	21,900	2,050.55	2,362.41	311.87	15.2%
150	35%	38,325	3,304.27	3,567.35	263.09	8.0%
150	50%	54,750	4,377.25	3,799.54	(577.72)	-13.2%
150	65%	71,175	5,407.10	3,799.54	(1,607.56)	-29.7%
150	80%	87,600	6,436.95	3,799.54	(2,637.41)	-41.0%
200	20%	29,200	2,725.60	3,135.64	410.04	15.0%
200	35%	51,100	4,397.23	4,742.23	344.99	7.8%
200	50%	73,000	5,826.79	5,045.94	(780.85)	-13.4%
200	65%	94,900	7,199.92	5,045.94	(2,153.98)	-29.9%
200	80%	116,800	8,573.05	5,045.94	(3,527.11)	-41.1%
300	20%	43,800	4,075.72	4,682.10	606.38	14.9%
300	35%	76,650	6,583.16	7,091.97	508.81	7.7%
300	50%	109,500	8,725.86	7,538.74	(1,187.13)	-13.6%
300	65%	142,350	10,785.56	7,538.74	(3,246.82)	-30.1%
300	80%	175,200	12,845.25	7,538.74	(5,306.52)	-41.3%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
E-221-8T time-of-use

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)	(G)		(H)
On-Peak kW	Off-Peak kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change		
						Amount (\$)	%	
						(F) - (E)	(G) / (E)	
10	30	20%	1,460	276.46	321.68	45.22	16.4%	
10	30	35%	2,555	344.65	387.99	43.34	12.6%	
10	30	50%	3,650	412.85	454.30	41.45	10.0%	
10	30	65%	4,745	481.04	520.61	39.57	8.2%	
10	30	80%	5,840	549.24	586.92	37.68	6.9%	
30	90	20%	4,380	771.53	895.45	123.92	16.1%	
30	90	35%	7,665	976.12	1,094.38	118.26	12.1%	
30	90	50%	10,950	1,180.71	1,293.31	112.60	9.5%	
30	90	65%	14,235	1,385.29	1,492.24	106.95	7.7%	
30	90	80%	17,520	1,589.88	1,691.17	101.29	6.4%	
75	225	20%	10,950	1,885.45	2,186.42	300.97	16.0%	
75	225	35%	19,163	2,396.95	2,683.78	286.83	12.0%	
75	225	50%	27,375	2,908.38	3,181.07	272.69	9.4%	
75	225	65%	35,588	3,419.88	3,678.43	258.55	7.6%	
75	225	80%	43,800	3,931.32	4,175.72	244.40	6.2%	
100	300	20%	14,600	2,504.29	2,903.63	399.34	15.9%	
100	300	35%	25,550	3,186.25	3,566.73	380.48	11.9%	
100	300	50%	36,500	3,868.20	4,229.83	361.63	9.3%	
100	300	65%	47,450	4,550.16	4,892.93	342.77	7.5%	
100	300	80%	58,400	5,232.11	5,556.03	323.92	6.2%	
150	450	20%	21,900	3,741.98	4,338.05	596.07	15.9%	
150	450	35%	38,325	4,764.91	5,332.70	567.79	11.9%	
150	450	50%	54,750	5,787.85	6,327.35	539.50	9.3%	
150	450	65%	71,175	6,810.78	7,321.99	511.21	7.5%	
150	450	80%	87,600	7,833.71	8,316.64	482.93	6.2%	
200	600	20%	29,200	4,979.67	5,772.46	792.79	15.9%	
200	600	35%	51,100	6,343.58	7,098.66	755.08	11.9%	
200	600	50%	73,000	7,707.49	8,424.86	717.37	9.3%	
200	600	65%	94,900	9,071.40	9,751.06	679.66	7.5%	
200	600	80%	116,800	10,435.31	11,077.26	641.95	6.2%	
300	900	20%	43,800	7,455.04	8,641.30	1,186.26	15.9%	
300	900	35%	76,650	9,500.91	10,630.59	1,129.68	11.9%	
300	900	50%	109,500	11,546.77	12,619.89	1,073.12	9.3%	
300	900	65%	142,350	13,592.64	14,609.19	1,016.55	7.5%	
300	900	80%	175,200	15,638.50	16,598.49	959.99	6.1%	

E-221-8T Average Energy On-Peak: 30%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
GS-SCHOOLS M Summer Shoulder (May, September & October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
					(E) - (D)	(F) / (D)
101	15%	11,060	1,946.67	2,252.65	305.98	15.7%
101	30%	22,119	2,887.23	3,256.20	368.97	12.8%
101	45%	33,179	3,827.87	4,259.84	431.97	11.3%
101	60%	44,238	4,768.42	5,263.39	494.97	10.4%
101	75%	55,298	5,709.06	6,267.04	557.98	9.8%
150	15%	16,425	2,653.50	3,072.79	419.29	15.8%
150	30%	32,850	4,050.42	4,563.28	512.86	12.7%
150	45%	49,275	5,447.35	6,053.78	606.43	11.1%
150	60%	65,700	6,844.27	7,544.27	700.00	10.2%
150	75%	82,125	8,241.20	9,034.76	793.56	9.6%
200	15%	21,900	3,374.79	3,909.72	534.93	15.9%
200	30%	43,800	5,237.36	5,897.05	659.69	12.6%
200	45%	65,700	7,099.92	7,884.37	784.45	11.0%
200	60%	87,600	8,962.49	9,871.69	909.20	10.1%
200	75%	109,500	10,825.06	11,859.01	1,033.95	9.6%
300	15%	32,850	4,817.37	5,583.58	766.21	15.9%
300	30%	65,700	7,611.22	8,564.57	953.35	12.5%
300	45%	98,550	10,405.08	11,545.55	1,140.47	11.0%
300	60%	131,400	13,198.93	14,526.54	1,327.61	10.1%
300	75%	164,250	15,992.78	17,507.52	1,514.74	9.5%
350	15%	38,325	5,538.66	6,420.51	881.85	15.9%
350	30%	76,650	8,798.16	9,898.33	1,100.17	12.5%
350	45%	114,975	12,057.65	13,376.14	1,318.49	10.9%
350	60%	153,300	15,317.15	16,853.96	1,536.81	10.0%
350	75%	191,625	18,576.64	20,331.77	1,755.13	9.4%
400	15%	43,800	6,259.96	7,257.45	997.49	15.9%
400	30%	87,600	9,985.09	11,232.09	1,247.00	12.5%
400	45%	131,400	13,710.23	15,206.74	1,496.51	10.9%
400	60%	175,200	17,435.37	19,181.38	1,746.01	10.0%
400	75%	219,000	21,160.50	23,156.03	1,995.53	9.4%

GS-SCHOOLS M Average Energy On-Peak %: 19%
GS-SCHOOLS M Average Energy Shoulder-Peak %: 20%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
GS-SCHOOLS M Summer Peak (June - August)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$) (E) - (D)	% (F) / (D)
101	15%	11,060	2,056.92	2,372.20	315.28	15.3%
101	30%	22,119	3,107.70	3,495.29	387.59	12.5%
101	45%	33,179	4,158.59	4,618.48	459.89	11.1%
101	60%	44,238	5,209.37	5,741.58	532.21	10.2%
101	75%	55,298	6,260.26	6,864.77	604.51	9.7%
150	15%	16,425	2,817.22	3,250.33	433.11	15.4%
150	30%	32,850	4,377.86	4,918.37	540.51	12.3%
150	45%	49,275	5,938.51	6,586.40	647.89	10.9%
150	60%	65,700	7,499.16	8,254.44	755.28	10.1%
150	75%	82,125	9,059.80	9,922.47	862.67	9.5%
200	15%	21,900	3,593.08	4,146.45	553.37	15.4%
200	30%	43,800	5,673.94	6,370.49	696.55	12.3%
200	45%	65,700	7,754.81	8,594.54	839.73	10.8%
200	60%	87,600	9,835.67	10,818.59	982.92	10.0%
200	75%	109,500	11,916.53	13,042.63	1,126.10	9.4%
300	15%	32,850	5,144.81	5,938.67	793.86	15.4%
300	30%	65,700	8,266.11	9,274.74	1,008.63	12.2%
300	45%	98,550	11,387.40	12,610.81	1,223.41	10.7%
300	60%	131,400	14,508.69	15,946.88	1,438.19	9.9%
300	75%	164,250	17,629.99	19,282.95	1,652.96	9.4%
350	15%	38,325	5,920.68	6,834.78	914.10	15.4%
350	30%	76,650	9,562.19	10,726.86	1,164.67	12.2%
350	45%	114,975	13,203.70	14,618.94	1,415.24	10.7%
350	60%	153,300	16,845.20	18,511.02	1,665.82	9.9%
350	75%	191,625	20,486.71	22,403.11	1,916.40	9.4%
400	15%	43,800	6,696.54	7,730.89	1,034.35	15.4%
400	30%	87,600	10,858.27	12,178.99	1,320.72	12.2%
400	45%	131,400	15,019.99	16,627.08	1,607.09	10.7%
400	60%	175,200	19,181.72	21,075.17	1,893.45	9.9%
400	75%	219,000	23,343.44	25,523.26	2,179.82	9.3%

GS-SCHOOLS M Average Energy On-Peak %: 18%
GS-SCHOOLS M Average Energy Shoulder-Peak %: 17%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
GS-SCHOOLS M Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
					(E) - (D)	(F) / (D)
101	15%	11,060	1,760.92	2,054.45	293.53	16.7%
101	30%	22,119	2,515.73	2,859.82	344.09	13.7%
101	45%	33,179	3,270.62	3,665.26	394.64	12.1%
101	60%	44,238	4,025.43	4,470.63	445.20	11.1%
101	75%	55,298	4,780.32	5,276.07	495.75	10.4%
150	15%	16,425	2,377.63	2,778.45	400.82	16.9%
150	30%	32,850	3,498.70	3,974.60	475.90	13.6%
150	45%	49,275	4,619.76	5,170.75	550.99	11.9%
150	60%	65,700	5,740.82	6,366.90	626.08	10.9%
150	75%	82,125	6,861.89	7,563.05	701.16	10.2%
200	15%	21,900	3,006.97	3,517.27	510.30	17.0%
200	30%	43,800	4,501.72	5,112.13	610.41	13.6%
200	45%	65,700	5,996.47	6,707.00	710.53	11.8%
200	60%	87,600	7,491.23	8,301.86	810.63	10.8%
200	75%	109,500	8,985.98	9,896.73	910.75	10.1%
300	15%	32,850	4,265.65	4,994.90	729.25	17.1%
300	30%	65,700	6,507.77	7,387.20	879.43	13.5%
300	45%	98,550	8,749.90	9,779.50	1,029.60	11.8%
300	60%	131,400	10,992.03	12,171.80	1,179.77	10.7%
300	75%	164,250	13,234.16	14,564.09	1,329.93	10.0%
350	15%	38,325	4,894.99	5,733.72	838.73	17.1%
350	30%	76,650	7,510.80	8,524.73	1,013.93	13.5%
350	45%	114,975	10,126.62	11,315.75	1,189.13	11.7%
350	60%	153,300	12,742.43	14,106.76	1,364.33	10.7%
350	75%	191,625	15,358.25	16,897.78	1,539.53	10.0%
400	15%	43,800	5,524.32	6,472.53	948.21	17.2%
400	30%	87,600	8,513.83	9,662.26	1,148.43	13.5%
400	45%	131,400	11,503.33	12,852.00	1,348.67	11.7%
400	60%	175,200	14,492.83	16,041.73	1,548.90	10.7%
400	75%	219,000	17,482.34	19,231.46	1,749.12	10.0%

GS-SCHOOLS M Average Energy On-Peak %: 25%
GS-SCHOOLS M Average Energy Shoulder-Peak %: 16%

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
GS-SCHOOLS L Summer Shoulder (May, September & October)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$) (E) - (D)	% (F) / (D)
401	15%	43,910	5,870.23	6,769.75	899.52	15.3%
401	30%	87,819	9,269.32	10,260.47	991.15	10.7%
401	45%	131,729	12,668.48	13,751.26	1,082.78	8.5%
401	60%	175,638	16,067.57	17,241.97	1,174.40	7.3%
401	75%	219,548	19,466.74	20,732.76	1,266.02	6.5%
600	15%	65,700	8,542.88	9,827.57	1,284.69	15.0%
600	30%	131,400	13,628.86	15,050.64	1,421.78	10.4%
600	45%	197,100	18,714.83	20,273.71	1,558.88	8.3%
600	60%	262,800	23,800.81	25,496.78	1,695.97	7.1%
600	75%	328,500	28,886.78	30,719.86	1,833.08	6.3%
800	15%	87,600	11,229.01	12,900.79	1,671.78	14.9%
800	30%	175,200	18,010.31	19,864.89	1,854.58	10.3%
800	45%	262,800	24,791.61	26,828.98	2,037.37	8.2%
800	60%	350,400	31,572.91	33,793.08	2,220.17	7.0%
800	75%	438,000	38,354.21	40,757.17	2,402.96	6.3%
1,000	15%	109,500	13,915.13	15,974.02	2,058.89	14.8%
1,000	30%	219,000	22,391.76	24,679.14	2,287.38	10.2%
1,000	45%	328,500	30,868.38	33,384.26	2,515.88	8.2%
1,000	60%	438,000	39,345.01	42,089.37	2,744.36	7.0%
1,000	75%	547,500	47,821.63	50,794.49	2,972.86	6.2%
1,500	15%	164,250	20,630.45	23,657.08	3,026.63	14.7%
1,500	30%	328,500	33,345.38	36,714.76	3,369.38	10.1%
1,500	45%	492,750	46,060.32	49,772.43	3,712.11	8.1%
1,500	60%	657,000	58,775.26	62,830.11	4,054.85	6.9%
1,500	75%	821,250	71,490.20	75,887.79	4,397.59	6.2%
3,000	15%	328,500	40,776.38	46,706.26	5,929.88	14.5%
3,000	30%	657,000	66,206.26	72,821.61	6,615.35	10.0%
3,000	45%	985,500	91,636.13	98,936.97	7,300.84	8.0%
3,000	60%	1,314,000	117,066.01	125,052.32	7,986.31	6.8%
3,000	75%	1,642,500	142,495.88	151,167.68	8,671.80	6.1%
GS-SCHOOLS L Average Energy On-Peak %:					20%	
GS-SCHOOLS L Average Energy Shoulder-Peak %:					17%	

Supporting Schedules:
N/A

Recap Schedules:
N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
0 - 99 kW = self contained
100 kW and above = instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
GS-SCHOOLS L Summer Peak (June - August)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	(F)		(G)
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Change		
					Amount (\$)	%	
					(E) - (D)	(F) / (D)	
401	15%	43,910	6,278.40	7,411.62	1,133.22	18.0%	
401	30%	87,819	10,085.65	11,544.18	1,458.53	14.5%	
401	45%	131,729	13,892.99	15,676.83	1,783.84	12.8%	
401	60%	175,638	17,700.23	19,809.39	2,109.16	11.9%	
401	75%	219,548	21,507.57	23,942.05	2,434.48	11.3%	
600	15%	65,700	9,153.61	10,787.95	1,634.34	17.9%	
600	30%	131,400	14,850.30	16,971.41	2,121.11	14.3%	
600	45%	197,100	20,547.00	23,154.86	2,607.86	12.7%	
600	60%	262,800	26,243.70	29,338.31	3,094.61	11.8%	
600	75%	328,500	31,940.40	35,521.76	3,581.36	11.2%	
800	15%	87,600	12,043.31	14,181.30	2,137.99	17.8%	
800	30%	175,200	19,638.90	22,425.91	2,787.01	14.2%	
800	45%	262,800	27,234.50	30,670.51	3,436.01	12.6%	
800	60%	350,400	34,830.10	38,915.11	4,085.01	11.7%	
800	75%	438,000	42,425.69	47,159.72	4,734.03	11.2%	
1,000	15%	109,500	14,933.01	17,574.65	2,641.64	17.7%	
1,000	30%	219,000	24,427.50	27,880.41	3,452.91	14.1%	
1,000	45%	328,500	33,922.00	38,186.16	4,264.16	12.6%	
1,000	60%	438,000	43,416.49	48,491.92	5,075.43	11.7%	
1,000	75%	547,500	52,910.99	58,797.67	5,886.68	11.1%	
1,500	15%	164,250	22,157.25	26,058.03	3,900.78	17.6%	
1,500	30%	328,500	36,399.00	41,516.66	5,117.66	14.1%	
1,500	45%	492,750	50,640.74	56,975.30	6,334.56	12.5%	
1,500	60%	657,000	64,882.48	72,433.93	7,551.45	11.6%	
1,500	75%	821,250	79,124.23	87,892.56	8,768.33	11.1%	
3,000	15%	328,500	43,830.00	51,508.16	7,678.16	17.5%	
3,000	30%	657,000	72,313.48	82,425.43	10,111.95	14.0%	
3,000	45%	985,500	100,796.97	113,342.69	12,545.72	12.4%	
3,000	60%	1,314,000	129,280.45	144,259.95	14,979.50	11.6%	
3,000	75%	1,642,500	157,763.94	175,177.22	17,413.28	11.0%	

GS-SCHOOLS L Average Energy On-Peak %: 18%
GS-SCHOOLS L Average Energy Shoulder-Peak %: 15%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
 - 0 - 99 kW = self contained
 - 100 kW and above = Instrument-rated

Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis at Present and Proposed Rates
GS-SCHOOLS L Winter (November - April)

(excludes bill reduction from transferring adjustor rates to base rates)

(A)	(B)	(C)	(D)	(E)	Change	
kW	Load Factor	Monthly kWh	Monthly Bill under Present Rates	Monthly Bill under Proposed Rates	Amount (\$)	%
					(E) - (D)	(F) / (D)
401	15%	43,910	5,212.96	6,249.37	1,036.41	19.9%
401	30%	87,819	7,954.79	9,219.71	1,264.92	15.9%
401	45%	131,729	10,696.68	12,190.12	1,493.44	14.0%
401	60%	175,638	13,438.52	15,160.46	1,721.94	12.8%
401	75%	219,548	16,180.41	18,130.87	1,950.46	12.1%
600	15%	65,700	7,559.45	9,048.95	1,489.50	19.7%
600	30%	131,400	11,661.99	13,493.40	1,831.41	15.7%
600	45%	197,100	15,764.52	17,937.85	2,173.33	13.8%
600	60%	262,800	19,867.06	22,382.30	2,515.24	12.7%
600	75%	328,500	23,969.60	26,826.75	2,857.15	11.9%
800	15%	87,600	9,917.76	11,862.63	1,944.87	19.6%
800	30%	175,200	15,387.81	17,788.57	2,400.76	15.6%
800	45%	262,800	20,857.86	23,714.50	2,856.64	13.7%
800	60%	350,400	26,327.91	29,640.43	3,312.52	12.6%
800	75%	438,000	31,797.96	35,566.37	3,768.41	11.9%
1,000	15%	109,500	12,276.07	14,676.32	2,400.25	19.6%
1,000	30%	219,000	19,113.64	22,083.73	2,970.09	15.5%
1,000	45%	328,500	25,951.20	29,491.15	3,539.95	13.6%
1,000	60%	438,000	32,788.76	36,898.57	4,109.81	12.5%
1,000	75%	547,500	39,626.33	44,305.98	4,679.65	11.8%
1,500	15%	164,250	18,171.85	21,710.52	3,538.67	19.5%
1,500	30%	328,500	28,428.20	32,821.65	4,393.45	15.5%
1,500	45%	492,750	38,684.54	43,932.77	5,248.23	13.6%
1,500	60%	657,000	48,940.89	55,043.90	6,103.01	12.5%
1,500	75%	821,250	59,197.23	66,155.02	6,957.79	11.8%
3,000	15%	328,500	35,859.20	42,813.15	6,953.95	19.4%
3,000	30%	657,000	56,371.89	65,035.40	8,663.51	15.4%
3,000	45%	985,500	76,884.58	87,257.65	10,373.07	13.5%
3,000	60%	1,314,000	97,397.27	109,479.90	12,082.63	12.4%
3,000	75%	1,642,500	117,909.96	131,702.15	13,792.19	11.7%

GS-SCHOOLS L Average Energy On-Peak %: 23%
GS-SCHOOLS L Average Energy Shoulder-Peak %: 19%

Supporting Schedules:

N/A

Recap Schedules:

N/A

NOTES TO SCHEDULE:

- 1) Bills do not include Adjustment, Regulatory Assessment, or Tax charges.
- 2) Present Rates are rates effective 7/1/2012.
- 3) For purposes of calculating the monthly bill, customers are categorized in this manner:
 - 0 - 99 kW = self contained
 - 100 kW and above = Instrument-rated

**Arizona Public Service Company
Test Year Ending December 2015
Typical General Service Bill Analysis**

**Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels**

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
<u>kW</u>	<u>Load Factor</u>	<u>Monthly kWh</u>	<u>Monthly Bill under Present Rates</u>	<u>Monthly Bill under Proposed Rates</u>	<u>Amount (\$)</u> (E) - (D)	<u>%</u> (F) / (D)

No typical bill analysis is presented for the following General Service Rate Schedules:

as no rate changes are proposed for these schedules.

**Arizona Public Service Company
Test Year Ending December 2015
Typical Classified Service Bill Analysis**

**Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels**

(A)	(B)	(C)	(D)	(E)	(F)	(G)
					Change	
<u>kW</u>	<u>Load Factor</u>	<u>Monthly kWh</u>	<u>Monthly Bill under Present Rates</u>	<u>Monthly Bill under Proposed Rates</u>	<u>Amount (\$)</u> (E) - (D)	<u>%</u> (F) / (D)

No typical bill analysis is presented for the following Classified Service Rate Schedules:

E-56
E-36 M
E-36 XL

as no rate changes are proposed for these schedules.

**Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Service Bill Analysis**

**Customer Bills at Varying Consumption Levels
at Present and Proposed Rate Levels**

(A)	(B)	(C)	(D)	(E)	Change	
<u>kW</u>	<u>Load Factor</u>	<u>Monthly kWh</u>	<u>Monthly Bill under Present Rates</u>	<u>Monthly Bill under Proposed Rates</u>	<u>Amount (\$)</u> <small>(E) - (D)</small>	<u>%</u> <small>(F) / (D)</small>

No typical bill analysis is presented for the following Residential Service Rate Schedules:

as no rate changes are proposed for these schedules.

Arizona Public Service Company
Test Year Ending December 2015
Typical Residential Bill Analysis at Present and Proposed Rates



Proposed Rate	Current Rate	Customers (subset)	Current Rates	Revenue Proposed Rates	\$ Change	%
R-XS	E-12	243,903	\$ 134,602,080	\$ 153,640,625	\$ 19,038,544	14.1%
R-Basic	E-12	145,456	174,501,614	200,540,561	26,038,948	14.9%
R-Basic L	E-12	76,970	152,941,702	180,856,638	27,914,936	18.3%
	Total	466,329	\$ 462,045,396	\$ 535,037,824	\$ 72,992,428	15.8%
TOU-E	ET-1	133,692	\$ 238,842,235	\$ 282,927,526	\$ 44,085,291	18.5%
	ET-2	295,363	494,258,948	578,358,523	84,099,575	17.0%
	Total	429,055	\$ 733,101,183	\$ 861,286,049	\$ 128,184,866	17.5%
R-2/R-3	ECT-1R	26,272	\$ 67,235,290	\$ 74,378,778	\$ 7,143,488	10.6%
	ECT-2	92,478	215,376,112	246,425,462	31,049,350	14.4%
	Total	118,750	\$ 282,611,402	\$ 320,804,240	\$ 38,192,838	13.5%
Total		1,014,134	\$ 1,477,757,981	\$ 1,717,128,113	\$ 239,370,132	16.2%

Notes:

- 1) Includes customers with 12 months of usage data from QAMI meters. Excludes Customers participating in net metering.
- 2) Revenue does not include Adjustments, Regulatory Assessment, or Tax charges.
- 3) Assumes like for like rate transition.

ARIZONA CORPORATION COMMISSION STAFF'S
FIFTH SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
OCTOBER 4, 2016

Staff 5.23: **Rate Design:** Please provide any studies performed by or for the Company that determine, estimate or calculate the unit costs for basic service charges for all classes. Provide the costs separated into components such as but not limited to meters, meter reading, billing, customer service, etc.

Response: The requested information is provided at Attachment APSRC01214.

In Miessner's Direct Testimony at pages 31-32, APS discusses the types of costs that are appropriate to recover through a monthly service charge, which includes costs that do not vary with customer's kW demand or kWh energy usage.

This list includes metering and billing, customer care and accounts, and a portion of the distribution grid costs such as the service entrance section and related point-of-delivery equipment, the secondary drop to the home, the distribution transformer, general grid operating costs such as cyber security, communications and controls, and other grid equipment that is used to ensure reliability, but is not related to the load on a distribution circuit.

APS is not requesting recovery of all of these costs through the basic service charge in the current case. The requested service charges for residential customers recover the metering, billing, and customer care costs, and only a small portion of the other grid costs discussed.



General Service/E-221/SL/DTD		General Service		E-20 (Church Rate)		E-32 TOU (0-100 kW)		E-32 TOU (101-400 kW)		E-32 TOU (401+ kW)		School TOU	
December Customer Count MW MWh	139,289 41,475 15,667,021	128,443 39,595 15,157,141	405 236 38,746	379 109 36,912				73 169 72,164		55 568 245,946		122 445 105,093	
Distribution (Transformers, Secondary & Services)		55,412,124	33.15	38,163,419	24.76	293,782	60.45	118,943	26.15	145,370	165.95	355,877	539.21
Distribution Costs for BSC		55,412,124	33.15	38,163,419	24.76	293,782	60.45	118,943	26.15	145,370	165.95	355,877	539.21
Distribution (Customer Accounts, Cust. Service, Sales)	13,950,060	8.35	12,882,572	8.36	45,032	9.27	37,705	8.29	15,494	17.69	36,894	55.90	35,243
	18,687,504	11.18	18,063,632	11.72	174,255	35.86	71,835	15.79	123,832	141.36	68,945	104.46	60,725
	1,510,211	0.90	1,392,469	0.90	4,397	0.90	4,113	0.90	792	0.90	597	0.90	41.48
	415,826	0.25	410,187	0.27	1,296	0.27	1,211	0.27	233	0.27	176	0.27	390
Revenue Cycle Costs for BSC		34,562,600	20.68	32,748,861	21.25	224,982	46.29	114,864	25.26	140,352	160.22	106,612	161.53
Total BSC		89,974,725	53.83	70,912,280	46.01	518,764	106.74	233,807	51.41	285,722	326.17	462,489	700.74
Total Residential													
December Customer Count MW MWh	1,059,292 73,645 13,518,425	473,340 24,640 3,689,073	429,763 34,271 6,464,264	118,890 11,976 2,801,983				35,988 2,624 530,434		1,311 135 32,670		1,311 135 32,670	
Distribution (Transformers, Secondary & Services)		173,409,381	13.64	58,751,263	10.34	80,145,215	15.54	28,194,122	19.76	6,025,110	13.95	293,670	18.67
Distribution Costs for BSC		173,409,381	13.64	58,751,263	10.34	80,145,215	15.54	28,194,122	19.76	6,025,110	13.95	293,670	18.67
Distribution (Customer Accounts, Cust. Service, Sales)	92,678,529	7.29	41,098,599	7.24	37,761,942	7.32	10,587,732	7.42	3,115,186	7.21	115,070	7.31	31,115
	81,516,159	6.41	32,709,158	5.76	29,706,953	5.76	8,219,855	5.76	10,498,288	24.31	381,905	24.28	60,725
	11,500,132	0.90	11,138,634	0.90	4,665,699	0.90	1,290,740	0.90	390,824	0.90	14,235	0.90	41.48
	3,389,741	0.27	3,314,322	0.27	1,375,231	0.27	380,470	0.27	115,301	0.27	4,198	0.27	390
Revenue Cycle Costs for BSC		189,084,581	14.88	80,460,913	14.17	73,509,845	14.25	20,478,796	14.35	14,119,598	32.70	515,408	32.76
Total BSC		362,493,942	28.52	139,212,176	24.51	193,455,061	29.79	48,673,918	34.12	20,144,799	46.65	809,078	51.43

	E-20, E-22 (0-100 kW)	E-32 (101-400 kW)	E-32 (401+ kW)	E-34	E-35	E-221 (Water Pumping)	Street Lighting	Dusk to Dawn
December Customer Count	122,044	4,259	1,028	32	46	1,450	1,153	8,243
MW	15,012	8,641	7,867	1,765	4,783	1,398	419	64
MWh	4,100,274	3,272,544	3,708,764	937,757	2,638,942	336,064	150,810	23,006
	\$/cust/mo	\$/cust/mo	\$/cust/mo	\$/cust/mo	\$/cust/mo	\$/cust/mo	\$/cust/mo	\$/cust/mo
Distribution (Transformers, Secondary & Services)	22,257,346	8,163,972	4,744,214	375,726	1,251,100	1,434,895	9,910,810	5,903,070
	15.20	19.74	12.44	0.38	0.46	0.42	0.71	0.68
Distribution Costs for BSC	22,257,346	8,163,972	4,744,214	375,726	1,251,100	1,434,895	9,910,810	5,903,070
	15.20	19.74	12.44	0.38	0.46	0.42	0.71	0.68
Distribution (Customer Accounts, Cust. Service, Sales)	11,125,735	842,547	495,252	87,549	161,120	206,515	124,164	736,809
Metering	14,443,876	1,920,379	867,664	136,094	196,027	623,871	35,855	-
Billing	1,324,669	45,926	9,890	304	456	15,741	0.90	89,483
Meter Reading	390,210	13,531	2,914	90	134	4,639	0.27	-
	0.27	0.26	0.24	0.24	0.24	0.27	0.90	0.90
Revenue Cycle Costs for BSC	27,284,490	2,822,383	1,375,720	224,037	357,737	890,767	136,681	826,292
	18.63	55.22	11.52	0.63	0.64	0.67	0.88	0.83
Total BSC	49,541,837	10,986,355	6,119,934	599,763	1,608,837	2,285,592	10,047,491	6,729,362
	33.83	214.96	496.10	0.59	2.91	0.56	726.18	68.03

December Customer Count
MW
MWh

Distribution (Transformers,
Secondary & Services)

Distribution Costs for BSC

Distribution (Customer
Accounts, Cust. Service, Sales)
Metering
Billing
Meter Reading

Revenue Cycle Costs for BSC

Total BSC

APS Proposed Pilot for E-32L TOU Customers Installing Storage

1. \$2M annual program cap for each year for the period of 2017-2019 funded through the DSMAC adjustor.
 - Eligibility is limited to E-32L customers and must be on a TOU rate
 - Cash incentive amounts would be limited to 50% of individual system cost and would not exceed \$100,000 per installation
 - Incentive payments would be paid commensurate with the duration of storage (at the rated continuous power) technology aligned with system benefits as follows:

Storage Duration	Amount of Incentive Paid
5 hours	100%
4 hours	80%
3 hours	60%
2 hours	40%
1 hour	20%

- All kWh stored and discharged through participating systems would be credited towards APS annual DSM compliance requirements
 - Participating systems must complete all required interconnection approvals prior to operation and include all required metering and communication infrastructure
2. Participating customers are eligible for a one-time demand forgiveness once per year where a single 15-minute demand interval would be omitted. The customer must initiate the request for this adjustment within 30 days of receiving their bill.
 3. Upon approval of the storage system interconnection, the existing billing basis for the ratchet value will be reset to reflect the anticipated kW demand reduction from the storage system.



ORIGINAL

0000175350

BEFORE THE ARIZONA CORPORATION COMMISSION**COMMISSIONERS**

DOUG LITTLE, CHAIR
TOM FORESE
BOB STUMP
BOB BURNS
ANDY TOBIN

Arizona Corporation Commission

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IN THE MATTER OF THE APPLICATION
OF
ARIZONA PUBLIC SERVICE COMPANY
FOR A HEARING TO DETERMINE THE
FAIR VALUE OF THE UTILITY PROPERTY
OF THE COMPANY FOR **RATEMAKING**
PURPOSES, TO FIX A JUST AND
REASONABLE **RATE** OF RETURN
THEREON, [AND] TO APPROVE **RATE**
SCHEDULES DESIGNED TO DEVELOP
SUCH RETURN.

(Teena Jibilian, Hearing Officer)

DOCKET NO. E-01345A-16-0036

**INTERVENOR GAYER'S
PREPARED DIRECT TESTIMONY**

IN THE MATTER OF FUEL AND
PURCHASED POWER PROCUREMENT
AUDITS FOR ARIZONA PUBLIC SERVICE
COMPANY.

DOCKET NO. E-01345A-16-0123

Richard Gayer, an Intervenor herein and a customer of Arizona Public Service (APS) in
Phoenix, Arizona, hereby submits his Prepared Direct Testimony.

Q1. What is your background and education?

A1. Gayer is a retired electronics engineer and lawyer with degrees B.S.E.E., M.S.E.E.,
and J.D. He gained some experience before the Commission when he represented himself in
Docket No. 13-0327 against Southwest Gas Corporation and obtained a settlement exposing the
previously hidden Monthly Weather Adjustment charges to all residential customers of SWGas.

Q2. Should APS's proposal for a mandatory demand charge be rejected?

A2. Yes, and for several reasons. First, unlike similar charges around the United States,
the charge sought by APS is mandatory and independent of customer characteristics. See APS's

INTERVENOR GAYER's PREPARED DIRECT TESTIMONY - 1



1 Response to Staff Data Request No. 12 at APSRC01454 (page 1 of 1) filed on 19 October 2016
2 (Adobe page 91/177). Such a charge is appropriate only for large users (*ibid.*), and few
3 residential users so qualify. Secondly, such a charge is complex and requires sophisticated and
4 expensive hardware and software to manage a customer's demand effectively. Thirdly, it is a
5 burden on Senior Citizens (persons over 65 years old) and especially on such persons who are
6 elderly (over 75). Finally, it is a burden on working families where two wage-earners are
7 struggling to make ends meet and have no time available to stagger the usage of their
8 appliances.

9
10 Q3. Should Senior Citizens, customers who are over 65, be allowed to select the
11 proposed Extra Small Rate independent of their demand or energy usage or size of their
12 principal residences?

13 A3. Yes. This is largely because of the foregoing complexity and expense of installing
14 equipment to effectively manage demand.

15
16 Q4. Should Senior Citizens be allowed to select the proposed Extra Small Rate if their
17 average monthly energy usage does not exceed 830 kilowatt-hours (up to 9960 kilowatt-hours
18 per year)?

19 A4. Yes. That would be an easy way to protect Senior Citizens from the complexity and
20 burden of dealing with demand charges.

21
22 Q5. Should Senior Citizens whose principal residences do not exceed 1800 square feet
23 be allowed to select the proposed Extra Small Rate?

24 A5. Yes, but only if the Commission rejects both of Gayer's proposals set forth above
25 under Questions 3 and 4. APS has long experience in verifying energy usage, but none in
26 verifying residential sizes.

1 Q6. Should all customers whose average monthly usage does not exceed 830 kilowatt-
2 hours (up to 9960 kilowatt-hours per year) be allowed to select the proposed Extra Small Rate?

3 A6. Yes. The limit of 600 proposed by APS is much too low. A demand rate that is
4 mandatory should be imposed only on customers whose energy usage is much closer to APS's
5 stated average of 1100 kilowatt-hours per month. Any demand rate should be applied, at least
6 initially, only to the larger energy users. They are likely to be better able to manage demand
7 because they have more energy usage to consider and many may be able to afford the high cost
8 of demand management equipment.

9 Gayer's proposed limit may be decreased to 600 three years after the effective date of the
10 Commission's Order in this case, but based only on the proven experience of APS during those
11 years and the Commission's ruling on an appropriate public motion by APS for such a decrease.

12
13 Q7. Should all customers whose principal residences do not exceed 1800 square feet be
14 allowed to select the proposed Extra Small Rate?

15 A7. Yes, but only if the Commission rejects Gayer's proposal set forth in Question 6,
16 above.

17
18 Q8. Should APS be required to use bill estimation, reading meters every other month or
19 every six months, for customers who do not have smart (AMI) meters?

20 A8. Yes. Sending readers out to read all non-AMI meters every month is wasteful and is
21 apparently designed to pressure users of such meters to convert to AMI meters. If the
22 Commission approves a six month cycle, then APS should be permitted to require one-time
23 deposits from customers on that cycle equal to one-half of a customer's total bills from the
24 previous 12 months.

25
26 Q9. Should APS be required to remove all smart (AMI) meters by the end of 2018 and
27 replace them with analog meters or digital meters that do not transmit or receive electrical,
28 electronic or radio signals and which digital meters lack contacts or other mechanism that could

1 be used to disconnect a customer's service if suitable hardware and software were activated in or
2 added to the meter?

3 A9. Yes. AMI meters are harmful for several reasons. Radiation from them sickens
4 almost five percent of the population, they are susceptible to hacking, especially disconnects, by
5 people from terrorists to nasty neighbors, their substandard contacts can cause house fires, their
6 detailed and granular measurements invade customers' privacy, and their lifetimes are short
7 compared to those of analog meters.

8
9 Q10. Should APS add security to protect its workers and installations from attacks by
10 customers who are angered to violence by the proposed mandatory demand charge?

11 A10. Yes. APS has over one million customers, a sufficiently large number for the rule
12 of one in a thousand to apply. That is, if government or a powerful corporation oppresses a
13 large number of people, most will just accept the oppression and some will object through
14 lawful and peaceful means. However, one-tenth of one percent are likely to resort to violence
15 against whatever assets of APS are exposed to the public. Therefore, APS should add a physical
16 security charge of about one dollar per month to all bills, thereby raising over ten million dollars
17 per year for that security.

18
19 Q11. Should APS protect its open wireless network of smart (AMI) meters from cyber
20 attacks?

21 A11. Yes. APS's wireless network presents an attractive target for terrorists, hackers,
22 and other trouble makers. Unauthorized access to any single meter provides immediate access
23 to many other meters on the network and eventually to almost the entire network. Among other
24 things, a hacker can disconnect one or more customers' power via the smart meters.

25 Gayer understands that APS currently uses 128-bit encryption in its smart meters, but that
26 can be broken by Amazon for no more than \$100. The Commission should require APS to
27 improve meter security by an order of magnitude within the next year or remove all smart
28 meters by the end of 2018.

1
2 Q12. Should the Commission continue to allow APS to pit one class of customers (with
3 rooftop solar) against another (those without rooftop solar)?

4 A12. No. Distributed generation (DG) benefits all APS customers, and full ("retail") net
5 metering should be continued to encourage more rooftop solar installations. DG also provides a
6 measure of protection against terrorists, since utility scale solar generation attracts terrorists who
7 can use inexpensive drones to damage such large installations.

8 As a customer without rooftop solar, Gayer is proud to continue to pay more (up to ten
9 percent) for his energy so that others may be encouraged to install rooftop solar.

10
11 Q13. Should APS provide a bill credit to customers who install demand controllers to
12 limit their demand charges, as other electrical utilities such as Black Hills Power company have
13 done? (See APS's Response to Staff's Data Request No. 12 at APSRC01469 for South Dakota
14 and APSRC01470 for Wyoming.)

15 A13. Yes. Demand charges can be shocking and expensive, and customers seldom have
16 advance warning regarding demand spikes so that they can reduce demand before a charge is
17 applied. Demand controllers can prevent such demand spikes in the first place.

18
19 Q14. What are the minimum system requirements for a smart (AMI) meter to begin to
20 provide some benefit to an APS customer?

21 A14. The smart meter must provide real time (minute-by-minute) data to the customer,
22 the customer must have a demand controller that communicates wirelessly or otherwise with the
23 smart meter, and the demand controller must have sufficiently sophisticated software to enable it
24 to connect or disconnect appliances to minimize demand peaks. Such a system would make
25 sense only for a large energy user with an abundance of money.

26
27 Q15. Should APS change its full name to reflect the service it is providing, to "Arizona
28 **Power Service**"?

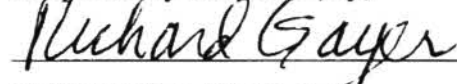
1 A15. Yes. The "public" in APS suggests that it is a governmental entity, similar in kind
2 to DPS, the Department of Public Safety. That is somewhat deceptive, since APS is a fully
3 private corporation with shareholders. Since APS provides power, it should change its full
4 name to Arizona Power Service. Its abbreviation and logo will remain the same; "APS" will not
5 change. (Gayer has been writing checks to Arizona Power Service since he arrived in Phoenix
6 in early 2004, and all of them have been accepted by APS in full payment of his monthly bills.)
7
8

9 **Proof of Service**

10 On 7 December 2016, I served copies of the foregoing on all parties on the "Service
11 List" in this case.
12

13 Dated: 7 December 2016

Respectfully submitted by,



RICHARD GAYER, Intervenor
526 West Wilshire Drive
Phoenix, AZ 85003
602-229-8954 (rgayer@cox.net)

ORIGINAL



BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

Arizona Corporation Commission

DOCKETED

DOUG LITTLE, CHAIR
TOM FORESE
BOB STUMP
BOB BURNS
ANDY TOBIN

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IN THE MATTER OF THE APPLICATION
OF
ARIZONA PUBLIC SERVICE COMPANY
FOR A HEARING TO DETERMINE THE
FAIR VALUE OF THE UTILITY PROPERTY
OF THE COMPANY FOR **RATEMAKING**
PURPOSES, TO FIX A JUST AND
REASONABLE **RATE** OF RETURN
THEREON, [AND] TO APPROVE **RATE**
SCHEDULES DESIGNED TO DEVELOP
SUCH RETURN.

(Teena Jibilian, Hearing Officer)

DOCKET NO. E-01345A-16-0036**INTERVENOR GAYER'S****FIRST SUPPLEMENTARY****PREPARED DIRECT TESTIMONY**

IN THE MATTER OF FUEL AND
PURCHASED POWER PROCUREMENT
AUDITS FOR ARIZONA PUBLIC SERVICE
COMPANY.

DOCKET NO. E-01345A-16-0123

Richard Gayer, an Intervenor herein and a customer of Arizona Public Service (APS) in Phoenix, Arizona, hereby submits his Prepared Direct Testimony.

Q1. Should APS be permitted to charge customers with non-AMI meters a monthly fee for reading their meters?

A1. No, there is no financial need. The cost of each meter reading is only 20.7 cents when spread over all APS residential customers, as explained below.

APS asserts that reading of analog meters is costly, but, based on APS's own numbers, replacing thousands of AMI meters and reading those that cannot be read electronically may cost even more.

In response to Woodward's 2.12, APS admits that it replaced over 19,000 AMI meters in 2014, over 22,000 in 2015 and over 20,000 up to October 2016. In that response, APS

1 "estimates less than 1% of monthly meter reads for reasons that include AMI meters not
2 communicating". From APS's website, we see that APS has over 1.2 million retail and
3 residential customers. (What about the commercial and industrial customers?) Anyway, 1% of
4 1.2 million is 12,000.

5 From Birdenkircher's Direct Testimony at page 9:20-21, "APS had a total of 16,568
6 customers" with analog meters in the Test Year. While that number is somewhat greater than
7 12,000, it is the same order of magnitude. But don't forget to add the 3,684 meters that cannot
8 be read electronically because of their locations for a new total of 15,684 meters. APS's
9 response to Woodward 2.10, from Birdenkircher and Miessner. There is no significant
10 difference between 16,568 and 15,684.

11 In addition, the admitted meter replacements per year are all above 19,000, which is
12 clearly greater than 16,568. So, the cost of reading analog meters has to be less than the cost of
13 dealing with AMI meter failures. (Round trips to customers' homes plus time to change the
14 meter plus the potential cost of the replacement meter.)

15 Finally, Decision 75047 of the Arizona Corporation Commission in Docket 13-0069
16 requires that APS report in 16-0036 "23g. The estimated bill impacts of spreading the cost
17 recovery of an opt-out program across all residential customers" (page 5 at lines 10-12). From
18 the above numbers and APS's demand for a \$15 monthly charge for reading analog meters, we
19 can easily calculate those bill impacts. Multiply \$15 by 16,568 and divide the product by
20 1,200,000. The result is 20.7 cents added to each customer's bill. Clearly, there is no basis for
21 punishing analog customers with a special meter reading charge.

22 Therefore, analog customers should not be charged anything for meter reading because
23 APS does not believe that dealing with thousands of AMI meter failures "constitutes a
24 'problem'". (APS response to Woodward's 2.12, first paragraph.)
25
26
27
28

1 **Proof of Service**

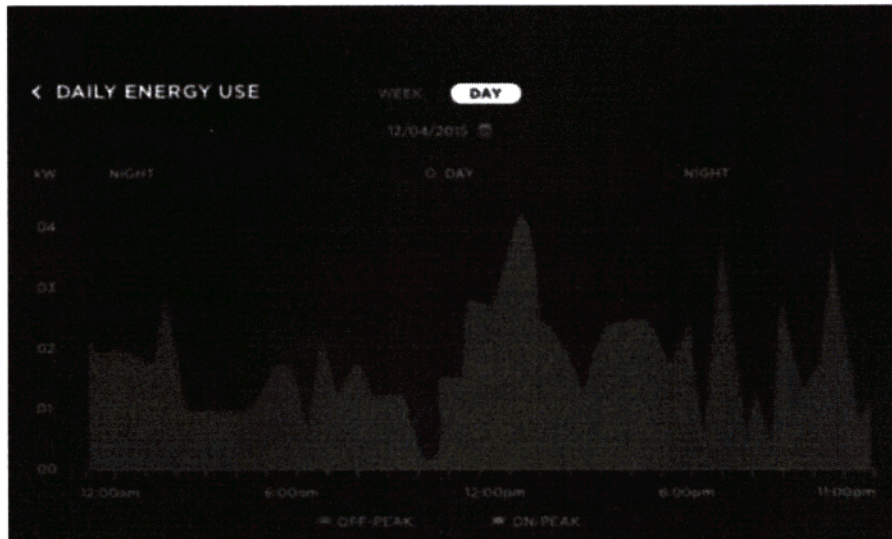
2 On 9 January 2017, I served copies of the foregoing on all parties on the "Service
3 List" in this case.

4
5 Dated: 9 January 2017

Respectfully submitted by,

Richard Gayer

6
7 RICHARD GAYER, Intervenor
8 526 West Wilshire Drive
9 Phoenix, AZ 85003
10 602-229-8954 (rgayer@cox.net)



Q. HOW WILL APS EXPLAIN THE NEW SERVICE PLANS TO CUSTOMERS?

A. APS will be implementing an education plan regarding changes to the service plans and will work with customers to refine its messaging. This plan will include bill inserts, website content, emails, and direct mail. It is our objective to make the transition to new plans as seamless for our customers as possible. APS will develop communications that are simple and easy to understand and which not only describe the specifics of the new plans, but also allow customers to be aware of behavioral actions they can take and programs they can participate in to help manage their demand and energy usage. APS will also offer an online rate calculator to customers so they can explore the new plans.

Importantly, APS will help customers identify which of the new rate plans is best for them based upon their past usage profile. APS will complete a plan comparison using each customer's historical usage profile, and move each customer to the new rate plan that is best suited for them. It is significant to note that although APS will move each customer to the best plan, the customer can select a different option if they so choose.





1 subsidies, better reflect the cost of service, provide incentives for the deployment of new
2 customer technologies and offer new rate and billing options. These new rate proposals
3 will make substantial progress on the specific subsidization of rooftop solar customers
4 who, based on the cost of service study sponsored by APS witness Leland Snook, are
5 currently only paying approximately 38% of the cost to provide them service.

6
7 Making progress on the cross-subsidization issue is critical in this proceeding. The total
8 cost shift from solar residential and commercial customers to non-solar residential and
9 commercial customers combined already totals \$42.7 million annually. It is especially
10 notable that this subsidy already exceeds the total annual subsidy currently provided to
11 low income customers. Assuming grandfathering, the 20 year rooftop solar subsidy
12 continues to grow rapidly at the rate of \$740,000 per day. By the time this case is
13 resolved in mid-2017, the total 20 year subsidy will total over \$1 billion. These
14 numbers are exclusive to the net energy metering subsidy and are in addition to the over
15 \$800 million in cash incentives committed or already paid to residential and commercial
16 customers over the last decade.

17
18 APS will also expand its limited income support from \$35.6 million during the Test
19 Year to approximately \$48 million and provide an alternative metering option for
20 residential customers that prefer not to have AMI meters.

21
22 APS does not propose to renew the alternative generation (AG-1) option for large
23 commercial and industrial (C&I) customers. At the same time, APS seeks to offer new
24 rate options for these types of customers, including a high load factor (HLF) rate, an
25 aggregation rate and an economic development Rate Rider. Other general service rates
26 will be largely left intact because the Company believes they are already properly
27 structured and reflect the cost of service.

- Intra-class subsidies within the residential class are significant but still manageable if addressed now. The subsidies include, but are not limited to, the cost shift inherent in NEM, and can be managed, and customers presently enjoying this subsidy can be “grandfathered.” The ability to insulate these customers from significant changes through grandfathering will not last long, perhaps not even until the Company’s next rate case unless significant progress is made now.
- It’s the right thing to do. Three-part rates better track cost of service and incent new behind-the-meter technologies for customers – essentially rendering utility rate design technology neutral.

Q. WHAT ARE THE CONSEQUENCES OF NOT MODERNIZING RATE DESIGN IN THIS PROCEEDING?

A. The costs to APS’s residential and commercial non-solar customers combined is already \$42.7 million annually and is growing rapidly. It is especially notable that this subsidy already exceeds the total annual subsidy currently provided to limited income customers. Making progress on the rooftop solar cross-subsidization issue is critical in this proceeding. In just the time it takes to process this case, that number will grow approximately \$20.1 million assuming the current pace of installations continues. Although APS has not requested recovery of those incremental costs in this case, we reserve the right to revise our request to include those costs if installations continue at such a rapid pace. If no progress is made in this case and the issue is deferred until APS’s next case (assuming that case is 3 years after this case), the total annual cost shift will have ballooned to \$102.9 million per year. The following table summarizes the annual and nominal 20 year cost shift.



1 equipment overloads. Non-residential customers may not opt-out of having a standard
2 meter because they are larger customers with more complex billing structures, including
3 demand rates based on 15 minute intervals for certain commercial customers, that
4 require the sophistication of an AMI meter.

5
6 **Q. DECISION NO. 75047 (APRIL 30, 2015) ORDERED APS TO PROVIDE**
7 **INFORMATION TO ASSIST THE COMMISSION IN EVALUATING ISSUES**
8 **RELATED TO CUSTOMERS WHO CHOOSE TO NOT HAVE AN AMI**
9 **METER. IS THERE ANY INFORMATION RELATING TO THAT ORDER**
10 **YOU WOULD LIKE TO DISCUSS?**

11 A. Yes, I will address the following topics: the total number of APS customers who have
12 elected to be served with non-standard (non-AMI) meters in the Test Year; a breakdown
13 by region of the number of APS customers who have elected to be served with non-
14 standard meters in the Test Year; the average per-customer, per-Test Year costs of
15 providing service with a non-standard meter as compared to the average per-customer,
16 test-year costs of providing service with an AMI meter; the Test Year costs and
17 expenses attributable to allowing customers to receive service through a non-standard
18 meter; and a comparative analysis of the costs and benefits of AMI meters as opposed to
19 the costs and benefits of non-standard meters. The other information requested in the
20 decision is provided in the direct testimony of Mr. Miessner.

- 21 • At the end of the Test Year, APS had a total of 16,568 customers who elected to be
22 served with non-AMI meters.



ORIGINAL



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BEFORE THE ARIZONA CORPORATION COMMISSION

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Arizona Corporation Commission

COMMISSIONERS

TOM FORESE, CHAIR
DOUG LITTLE
BOB STUMP
BOB BURNS
ANDY TOBIN

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IN THE MATTER OF THE APPLICATION
OF
ARIZONA PUBLIC SERVICE COMPANY
FOR A HEARING TO DETERMINE THE
FAIR VALUE OF THE UTILITY PROPERTY
OF THE COMPANY FOR RATEMAKING
PURPOSES, TO FIX A JUST AND
REASONABLE RATE OF RETURN
THEREON, [AND] TO APPROVE RATE
SCHEDULES DESIGNED TO DEVELOP
SUCH RETURN.

(Teena Jibilian, Hearing Officer)

DOCKET NO. E-01345A-16-0036

**INTERVENOR GAYER'S
DIRECT TESTIMONY IN
OPPOSITION TO
SETTLEMENT AGREEMENT**

IN THE MATTER OF FUEL AND
PURCHASED POWER PROCUREMENT
AUDITS FOR ARIZONA PUBLIC SERVICE
COMPANY.

DOCKET NO. E-01345A-16-0123

Richard Gayer, an Intervenor herein, hereby submits his Opposition to the Settlement Agreement filed on March 27, 2017.

Definitions: "APS", "you" and "your" refer to the Arizona Public Service Company, the utility involved in this rate case.

Gayer submits no opposition to the "Revenue Requirements" other than to state that the ROE of 10 percent is much too generous.

Q 1. Should the name of APS be changed to Arizona POWER Service?

A 1. Yes. "Public" deceptively suggests that APS is part of the government of the State of Arizona. In fact, APS is a large private corporation with securities traded on the New York Stock Exchange. The "service" that APS provides is POWER, and no document regarding APS



1 that I have seen states its full name. Therefore, APS may proudly change its name without
2 having to revise any of its stationary, bills or other documents.

3
4 Gayer opposes the following provisions under "Rate Design".

5
6 **XIX (19). Residential Rate Availability**

7 Q 19-1. What is unfair regarding rate availability?

8 A 19-1. New customers should be able to select R-Basic without a waiting period. Time
9 of Use rates are likely to be confusing to a new customer without previous experience with such
10 rates. Because of likely customer errors that are not their fault, APS will enjoy a bonanza from
11 unnecessarily high bills for 90 days.

12 The application of TOU rates should always be voluntary, as are demand rates. If the
13 Commission approves mandatory TOU rates for new customers, then such rates should apply
14 for no more than one billing cycle (approximately 30 days) to minimize financial damages to
15 APS's customers.

16
17 **XXVI (26). Effective Date of Rate Plans**

18 Q 26-1. What about the "information on options" that APS will provide to customers?

19 A 26-1. That information should include an explanation of the risks of TOU rates,
20 especially in view of the long interval from 3:00 pm to 8:00 pm.

21
22 **XXVIII (28). AZ Sun II**

23 Q 28.2. (re: (d)) Compare the cross-subsidization of AZ Sun II with cross-subsidization
24 of non-AMI meter reading charges. Assume that AZ Sun II is a worthwhile program. Also
25 assume that APS's agreed upon cost of reading such meters is \$5 per reading and that APS has
26 about 16,568 customers with non-AMI meters. Assume further that APS has a total of about 1.2
27 million customers.

1 A 28.2. Paragraph 28.2(d) provides for between \$10 million and \$15 million per year for
2 this project to be paid from monies collected by APS from its customers. This amounts to a
3 cross-subsidy of between \$8.33 and \$12.50 per year per customer, or about \$0.69 to \$1.04 per
4 month.

5 Cross-subsidization of non-AMI reading involves spreading the product of \$5 times 12
6 times 16,568 equals \$994,080 among 1.2 million customers, or \$0.89 per month.

7 So, if effectively charging each customer about 87 cents per month for AZ Sun II is fair,
8 then charging them about 89 cents per month for the non-AMI readings would also be fair.

9
10 **XXX (30). AMI Opt-Out and Schedule 1.**

11 Q 30-1. Are AMI Meters really smart?

12 A 30-1. No. They offer no benefits to customers and they present four dangers and risks
13 to them. For a list of purported benefits, see APS's Response to Gayer's Data Request No. 2.23,
14 set forth here for convenience.

15 Gayer 2.23: At this point in time, how do smart (AMI) meters benefit residential
16 customers, if at all? Regarding any potential such benefits in the future, please list them and
explain each one, including its cost to a customer and/or to APS.

17 Response: AMI Meters benefit APS customers in various ways:

18 1. Lower APS operating costs and therefore rates by not having to roll trucks for monthly
reads, customer move in/move outs, meter rate changes (customers changing from one rate to
another).

19 2. Reduced APS truck rolls results in lower air pollution from vehicles benefitting
everyone.

20 3. Granular usage data (hourly intervals) is made available on aps.com to help customers
understand when they use power and how much they use.

21 4. Using the hourly intervals, customers have the ability to get alerts specific to usage and
bill amounts.

22 5. Limits customer delay in connecting/disconnecting service as physical visit is not
required.

23
24 Item three may initially be viewed as a benefit, but its lack of fine detail (one hour is far
25 too coarse) and the one-day delay renders that data useless.

26
27 Risk One: Lack of cyber security = Hacking. AMI meters present a golden opportunity
28 for hackers or terrorists in the form of an open wireless network with only 128-bit encryption.

1 Risk Two: House fires. Unlike the ultra-reliable electromagnetic meters with spark gaps
2 to absorb surges, AMI meters have only solid state surge protection. Such protection is
3 necessarily limited.

4
5 Risk Three: Invasion of Privacy. AMI meters collect granular data in increments as small
6 as one minute. These data are valuable to commercial companies who desire to learn about
7 customers' habits and solicit their business accordingly. Any sale or transfer of such data
8 without the express permission of a customer will violate the customer's common law right to
9 privacy, thereby leading to a lawsuit for damages.

10
11 Risk Four: Microwave Health Hazard. Three to five percent of the general population is
12 susceptible to microwave radiation at even relatively low levels. According to the emailed
13 complaint of Customer Jean Griesenback filed in Docket 16-0123 on March 27, 2017, Jean
14 suffered from popping noises in the ears in the home in Sedona, but the noises stopped when
15 APS replaced the AMI meter with a non-AMI meter. Subsequently, she visited a private home
16 in North Carolina and the popping noises returned. Upon inquiry, she learned that the house
17 there was served by an AMI meter.

18 My neighborhood in the Willo Historic District in Phoenix has about 1500 residents;
19 there is no reason for 45 or more resident should be exposed to sickening radiation.

20
21 Q 30-2. Should customers who prefer safe meters be charged every month for reading
22 their non-communicating meters?

23 A 30-2 No. The cost of reading their 16,568 meters should be spread over all of APS' s
24 1.2 million customers, as suggested in Decision 75047, paragraph 23(g). APS admits that its
25 cost of reading each meter is only Five Dollars per month. If the cost is spread, then every
26 customer would pay about 89 cents more per month.

1 Q 30-3. Should customers who choose the relative safety of non-communicating meters
2 be viewed as potentially dangerous persons in Service Schedule One, paragraph 8.5 (D)?

3 A 30-3. No. Subdivision (D) under "Discontinuation of Non-Standard Metering"
4 provides that "Company employees have received verbal or physical threats, including, but not
5 limited to, verbal threats while installing meters or performing maintenance to Company
6 equipment, and physical weapons or dogs." This provision MUST be deleted !
7

8 Q 30-3. Should customers who do not have AMI meters be required to give APS
9 personnel direct contact with their meters within the boundaries of their property when APS
10 personnel may read the meters using binoculars from a convenient location outside of their
11 property?

12 A 30-3. No. Such a requirement invades a customer's privacy and forces the customer to
13 purchase and install a special lock for APS personnel to use for access or else to leave his or her
14 property insecure on meter reading days. Since such customers do not have a demand rate or
15 time of use rate, there is no justification whatsoever for trespassing on their properties to obtain
16 personal data from their meters.
17

18 Q 30-4. Should APS customers with non-AMI meters be able to obtain Bill Estimation
19 under Decision No. 75752?

20 A 30-4. Yes. Decision No. 75752 provides several methods for bill estimation, and
21 Gayer was expressly invited in that decision to intervene in *this* docket and to submit his request
22 for bill estimation here. *Id.*, at ¶ 36 ("Therefore, Staff concludes that Mr. Gayer's concerns are
23 best addressed in the current APS rate case Docket No. E-01345A-16-0036 ...")

24 A customer who chooses this option may be required to deposit an amount equal to his or
25 her estimated bills for the interval between actual meter readings. For example, if a customer
26 chooses a six month interval, then he or she may be required to post a deposit to cover that
27 interval. Upon the actual reading, the customer shall be required to pay (or receive) the balance
28 and to pay a new deposit to cover the next six months. To be eligible for bill estimation, a

1 customer should have been a customer of APS for at least 12 months in the same house or
2 apartment.

3
4 Q 30-5. Should non-AMI customers be allowed to submit to APS self-readings of their
5 meters every month?

6 A. 30-5. Yes. Self-reading has long been a method used by APS to obtain meter
7 readings from its customers. Verification of readings can be performed every six months by
8 APS employees. Paying an employee to read the meter monthly cannot be rationally justified;
9 charging the customer \$5 *every* month is just punishment. With self-reading, a customer would
10 pay only \$10 per year rather than \$60.

11
12 Q 30-6. Should non-AMI customers be allowed to elect APS's "Budget Billing" plan,
13 wherein a customer pays the same monthly amount over a twelve month period, subject to
14 periodic adjustment by APS?

15 A 30-6. Yes. There is no reason to charge a non-AMI customer for monthly meter
16 readings if he or she has been a customer for at least 12 consecutive months (so that a monthly
17 average may be calculated).

18
19 **Proof of Service**

20 On 01 April 2017, I served copies of the foregoing on all parties on the "Service List"
21 in this case.

22
23 Dated: 01 April 2017

Respectfully submitted by,



RICHARD GAYER, Intervenor
526 West Wilshire Drive
Phoenix, AZ 85003
602-229-8954 (rgayer@cox.net)



July 2012

SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES

The following TERMS AND CONDITIONS and any changes authorized by law will apply to Standard Offer and Direct Access services made available by Arizona Public Service Company (Company), under the established rate or rates authorized by law and currently applicable at time of sale.

Definitions

- a. Applicant means a person requesting the utility to supply electric service. [A.A.C. R14-2-201-(2)]
- b. Application means a request to the utility for electric service, as distinguished from an inquiry as to the availability or charges for such service. [A.A.C. R14-2-201-(3)]
- c. Billing Month means the period between any two regular readings of the utility's Meters at approximately 30 day intervals. [A.A.C. R14-2-201-(5)]
- d. Billing Period means the time interval between two consecutive Meter readings that are taken for billing purposes. [A.A.C. R14-2-201-(6)]
- e. Customer means the person or entity in whose name service is rendered, as evidenced by the signature on the Application or contract for that service, or by the receipt and/or payment of bills regularly issued in his name regardless of the identity of the actual user of the service. [A.A.C. R14-2-201-(9)]
- f. Delinquent Bill means a bill in which current electric charges are considered past due. (15 calendar days after the statement date)
- g. Demand means the rate at which power is delivered during any specified period of time. Demand may be expressed in kilowatts, kilovolt-amperes, or other suitable units. [A.A.C. R14-2-201-(12)]
- h. Distribution Lines means the utility lines operated at distribution voltage which are constructed along public roadways or other bona fide rights-of-way, including Easements on Customer's property. [A.A.C. R-14-2-201-(13)]
- i. Easement means a property owner grants the right to use land they own ("Grantor") to another party. An easement gives Company the right to have Company lines on property not owned by the Company. This allows Company to construct, replace, repair, operate and maintain electrical equipment for the safe transmission and distribution of electricity. The Grantor may continue to use the land along the easement within certain limitations.
- j. Landlord Automatic Transfer of Service Agreement is a legal contract established between the customer (landlord) and Company, which provides continuous service to the landlord between tenants without incurring a service establishment charge to the landlord.
- k. Master meter means a meter used for measuring or recording the flow of electricity that has passed through it at a single location where said electricity is distributed to tenants or occupants for their individual usage. [A.A.C. R14-2-201(23)]
- l. Meter means the instrument used for measuring and indicating or recording the flow of electricity that has passed through it. [A.A.C. R14-2-201(25)]

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: David J. Rumolo
Title: Manager, Regulation and Pricing
Original Effective Date: December 1951



A.C.C. No. 5804
Canceling A.C.C. No. 5765
Service Schedule 1
Revision No. 35
Effective: July 1, 2012



**SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES**

6.6.3 Multi-Unit Residential High Rise Developments (developments consisting of apartments, condominiums or townhouse developments built with four or more floors, usually using elevators for accessing floors) – Company will allow Master Metering for residential units where the residential units are privately owned, provided the building will be served by a centralized heating, ventilation and/or air conditioning system, and each residential unit shall be individually sub-metered and responsible for energy consumption of that unit.

6.6.3.1 Sub-metering shall be provided and maintained by the builder or homeowners association.

6.6.3.2 Responsibility and methodology for determining each unit's energy billing shall be clearly specified in the original bylaws of the homeowners association, a copy of which must be provided to Company prior to Company providing the initial extension.

7. Termination of Service

7.1 With Notice - Company may without liability for injury or damage, and without making a personal visit to the site, disconnect service to any Customer for any of the reasons stated below, provided Company has met the notice requirements established by the Arizona Corporation Commission:

7.1.1 A Customer violation of any of the applicable rules of the Arizona Corporation Commission or Company Tariff.

7.1.2 Failure of the Customer to pay a Delinquent Bill for services provided by Company.

7.1.2.1 Additional notice will not be provided when Customer makes payments to avoid/stop non-payment disconnection with a dishonored payment. Prior to reconnection of service, repayment of those funds and all other delinquent amounts will be required in cash, money order, or certified funds.

7.1.2.2 Additional notice will not be provided when Customer pays to reconnect service with a dishonored payment. Prior to reconnection of service, payment of those funds and all other delinquent amounts will be required in cash, money order or certified funds.

7.1.3 The Customer's breach of a written contract for service.

7.1.4 Failure of the Customer to comply with Company's deposit requirements.

7.1.5 Failure of the Customer to provide Company with satisfactory and unassisted access to Company's equipment.

7.1.6 When necessary to comply with an order of any governmental agency having jurisdiction.



**SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES**

- 7.1.7 Failure of a prior Customer to pay a Delinquent Bill for utility services where the prior Customer continues to reside on the premises.
 - 7.1.8 Failure to provide or retain rights-of-way or Easements necessary to serve the Customer.
 - 7.1.9 Company learns of the existence of any condition in Section 2.4, Grounds For Refusal of Service.
- 7.2 Without Notice - Company may without liability for injury or damage disconnect service to any Customer without advance notice under any of the following conditions:
 - 7.2.1 Company observes, or has evidence of, a hazard to the health or safety of persons or property.
 - 7.2.2 Company has evidence of Meter Tampering or fraud.
 - 7.2.3 Company has evidence of unauthorized resale or use of electric service.
 - 7.2.4 Failure of the Customer to comply with the curtailment procedures imposed by Company during a supply shortage.
- 7.3 Restoration of Service - Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of Company.
- 8. Removal of Facilities - Upon termination of service, Company may without liability for injury or damage, dismantle and remove its facilities installed for the purpose of supplying service to the Customer, and Company shall be under no further obligation to serve the Customer.
- 9. Successors and Assigns - Agreements for Service shall be binding upon and for the benefit of the successors and assigns of the Customer and Company, but no assignments by the Customer shall be effective until the Customer's assignee agrees in writing to be bound and until such assignment is accepted in writing by Company.
- 10. Warranty - THERE ARE NO UNDERSTANDINGS, AGREEMENTS, REPRESENTATIONS, OR WARRANTIES, EXPRESS OR IMPLIED (INCLUDING WARRANTIES REGARDING MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE), NOT SPECIFIED HEREIN OR IN THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION CONCERNING THE SALE AND DELIVERY OF SERVICES BY COMPANY TO THE CUSTOMER. THESE TERMS AND CONDITIONS AND THE APPLICABLE RULES OF THE ARIZONA CORPORATION COMMISSION STATE THE ENTIRE OBLIGATION OF COMPANY IN CONNECTION WITH SUCH SALES AND DELIVERIES.



**SERVICE SCHEDULE 1
TERMS AND CONDITIONS FOR
STANDARD OFFER AND DIRECT ACCESS SERVICES**

(B) If a termination is in underground equipment the reconnection charge will be \$135.00 plus applicable adjustments.

8. Metering & Metering Equipment

8.1 Standard Metering - The Company's standard method of measuring energy usage is through the use of Automated Metering Infrastructure (AMI) metering equipment. All customers will be served using the Company's standard metering equipment unless:

(A) the customer is in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used; or

(B) the customer meets all eligibility requirements for non-standard metering and voluntarily requests non-standard metering.

8.2 Non-Standard Metering - The Company's non-standard billing meter is the digital meter. A digital meter records energy electronically and displays the usage measurements. This meter does not employ any communications technology and must be read manually each month. Certain optional rates may not be available to customers who select a non-standard meter.

8.3 Non-Standard Metering Eligibility - Only residential customers, in whose name service is being provided, may request non-standard metering. Customers who have an existing, purchased or leased rooftop solar distributed generation (DG) system, or customers with newly installed rooftop solar, are not eligible for non-standard metering.

8.4 Non-Standard Metering Charges - The following charges will apply when a customer voluntarily requests, and is granted, non-standard metering:

(A) Monthly Meter Reading Charge: \$15.00

(B) Non-Standard Metering Set-up Fee: A \$70.00 one-time charge for customers with existing AMI meter or \$50.00 one-time charge for customers without existing AMI meter.

8.5 Discontinuation of Non-Standard Metering - The Company may replace a non-standard meter with a standard meter, without notifying the customer prior to replacement, under any of the following conditions:

(A) Company employees observe or have evidence of a safety hazard to employees, customers, or Company or customer property.

(B) Company employees observe or have evidence of meter tampering, energy diversion, or fraud.

(C) Company has evidence of unauthorized resale of electricity.

(D) Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to Company equipment, and physical threats such as weapons or dogs.

ARIZONA PUBLIC SERVICE COMPANY
Phoenix, Arizona
Filed by: Charles A. Miessner
Title: Manager, Regulation and Pricing
Original Effective Date: December 1951



A.C.C. No. xxxx
Canceling A.C.C. No. 5804
Service Schedule 1
Revision No. 36
Effective: xxxx xx, xxxx

Your electricity bill
April 13, 2017

Richard Gayer

Your account number
2644510000

Service plan: Standard Rate

Meter number: DN0879

Meter reading cycle: 09

Charges for electricity services

Cost of electricity you used

Customer account charge	\$1.83
Delivery service charge	\$8.13
Environmental benefits surcharge	\$3.38
Federal environmental improvement surcharge	\$0.05
System benefits adjustment	-\$0.15
System benefits charge	\$0.89
Power supply adjustment*	-\$0.41
Metering*	\$2.61
Meter reading*	\$1.80
Billing*	\$2.03
Generation of electricity*	\$17.76
Federal transmission and ancillary services*	\$1.57
Federal transmission cost adjustment*	\$2.15
Four-Corners adjustment	\$0.74
LFCR adjustor	\$0.97
Cost of electricity you used	\$43.35

Taxes and fees

Regulatory assessment	\$0.12
State sales tax	\$2.48
County sales tax	\$0.31
City sales tax	\$1.20
Franchise fee	\$0.87
Cost of electricity with taxes and fees	\$48.33

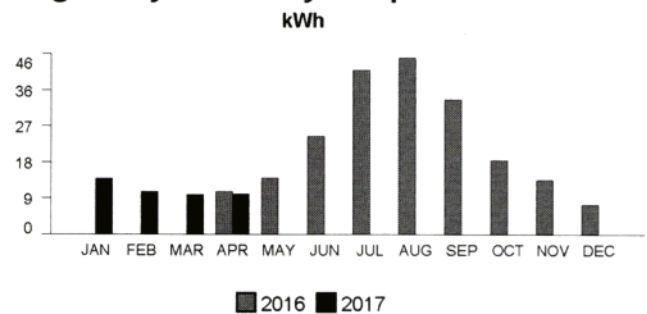
Total charges for electricity services \$48.33

* These services are currently provided by APS but may be provided by a competitive supplier.

Amount of electricity you used

Meter reading on Apr 13	15841
Meter reading on Mar 15	15540
Total electricity you used, in kWh	301

Average daily electricity use per month



Comparing your monthly use

	This month	Last month	This month last year
Billing days	29	30	30
Average outdoor temperature	70°	64°	71°
Your total use in kWh	301	306	328
Your average daily cost	\$1.67	\$1.63	\$1.75



Gayer Exhibit

10

Meter test in shop	\$ 44.00	\$ 30.00	\$ 14.00
Meter test at site	\$ 93.00	\$ 50.00	\$ 43.00
Trip Charge - Residential	\$ 22.00	\$ 16.00	\$ 6.00
Trip Charge - Nonresidential	\$ 26.00	\$ 16.00	\$ 10.00

Q. PLEASE DESCRIBE THE PROPOSED AMI OPT-OUT OPTION.

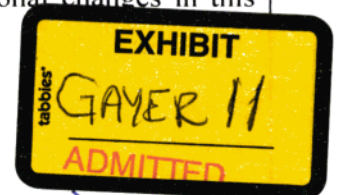
A. The AMI opt-out option allows customers to be served with a digital meter and manual meter reading instead of the AMI system. Details of the meter technology and related program information are provided in the Direct Testimony of Mr. Scott Bordenkircher. There are additional charges to cover the one-time special installation cost and the monthly cost of reading the meter manually with APS personnel rather than automatically through the AMI communication network. The one-time installation charge is \$70, while the on-going meter reading charge is \$15 per month. These charges can be found in Service Schedule 1.

Q. WHAT ARE THE COMPANY'S PROPOSED REVISIONS TO SERVICE SCHEDULE 3?

A. Schedule 3, which provides the conditions and terms for line extensions, was also reorganized and rewritten to be easier to understand. A definitions section was added to clarify current business practices and the implementation of certain terms. A summary of the proposed changes, explanations and the reasons for the changes are provided in Attachment CAM-06DR.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO SERVICE SCHEDULE 8?

A. Not in this rate case. Service Schedule 8 is being separately considered in Docket E-01345A-15-0386 and, therefore, APS is not proposing any additional changes in this rate case filing.



Miessner Direct

11



SERVICE SCHEDULE 1 TERMS AND CONDITIONS FOR STANDARD OFFER AND DIRECT ACCESS SERVICES

(C) Customers in a remote location where wireless technology is not available or AMI equipment cannot otherwise be used [see 8.1(A)] will not be billed a non-standard meter reading charge.

8.5 Discontinuation of Non-Standard Metering - The Company may replace a non-standard meter with a standard meter, without notifying the customer prior to replacement, under any of the following conditions:

- (A) Company employees observe or have evidence of a safety hazard to employees, customers, or Company or customer property.
- (B) Company employees observe or have evidence of meter tampering, energy diversion, or fraud.
- (C) Company has evidence of unauthorized resale of electricity.
- (D) Company employees have received verbal or physical threats, including, but not limited to, verbal threats while installing meters or performing maintenance to Company equipment, and physical threats such as weapons or dogs.
- (E) All terms and conditions in Section 7, regarding termination of service, will also apply.

8.6 Measuring Customer Service - All energy sold to the Customer by Company will be measured by commercially acceptable measuring devices. Where it is impractical to meter loads, such as street lighting, security lighting, or special installations, consumption will be determined by Company. The readings of the Meter will be conclusive as to the amount of electric power supplied to the Customer unless there is evidence of Meter Tampering or energy diversion or unless a test reveals the Meter is in error by more than 3%, either fast or slow.

8.7 Meter Rereads - When requested by Customer, APS will reread the customer's Meter within 10 working days after the request. The cost of each reread is \$14.00 plus applicable adjustments if the original reading was not in error.

8.8 Meter Testing - APS tests its Meters regularly in accordance with a Meter testing and maintenance program approved by the Arizona Corporation Commission. APS will individually test a Company owned and maintained Meter upon Customer request.

If after testing, a Meter is found to be more than 3% in error, either fast or slow, correction will be made of previous readings and adjusted bills will be rendered.

8.9 Meter Test Charge - If the Meter is found to be within the plus or minus 3% limit, Company may charge the Customer \$44.00 plus applicable adjustments for Meter test if the Meter is removed from the site and tested in the meter shop, or \$93.00 plus applicable adjustments if the Meter remains on site and is tested in the field.

8.10 Meter Tampering - If there is evidence of Meter Tampering or energy diversion, the Customer, person, or entity demonstrated to have tampered with the Meter, or benefited from the tampering or diversion will be billed for the estimated





Supervisory Capacitor Bank Controls

A capacitor is an electrical device that is used to correct voltage or power factor issues that occur with normal grid operations. This improves the overall efficiency of the utility system and ensures power quality for customer end-use equipment. Capacitors are installed in groups (called “cap banks”,) and are used to maintain proper voltage levels along the length of a feeder; from substation to end-of-line. APS is in the process of upgrading its capacitor bank communication control systems to allow for two-way communications between these devices and the operations control center. This has allowed distribution system operators to monitor the status of the cap banks and mitigate abnormal voltage levels remotely. The ability to dynamically control cap banks is especially critical when integrating higher penetration levels of distributed energy. By the end of 2016, APS will have upgraded over 300 cap banks.

Integrated Volt-VAR Control (IVVC)

IVVC is an automated system of capacitors and voltage regulators that are able to autonomously control voltage levels along a distribution feeder. This includes functionality for flattening (or leveling out) the voltage across a long distance feeder, thereby enabling a reduction in energy production. This system also provides necessary support for rooftop solar by mitigating the negative voltage effects of intermittent power production along a feeder. On feeders where IVVC is installed, customers benefit by having a higher level of power quality, which is necessary for the proper functioning of consumer appliances, and the increased ability to support customer-sited energy resources. APS has been installing IVVC systems since 2012; there are currently 6 installed, and the Company anticipates having a total of 28 by the end of June 2017.

RICHARD GAYER'S
SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
AND
DOCKET NO. E-01345A-16-0123
DECEMBER 17, 2016

Gayer 2.23: At this point in time, how do smart (AMI) meters benefit residential customers, if at all? Regarding any potential such benefits in the future, please list them and explain each one, including its cost to a customer and/or to APS.

Response: AMI Meters benefit APS customers in various ways:

1. Lower APS operating costs and therefore rates by not having to roll trucks for monthly reads, customer move in/move outs, meter rate changes (customers changing from one rate to another)
2. Reduced APS truck rolls results in lower air pollution from vehicles benefitting everyone
3. Granular usage data (hourly intervals) is made available on aps.com to help customers understand when they use power and how much they use.
4. Using the hourly intervals, customers have the ability to get alerts specific to usage and bill amounts.
5. Limits customer delay in connecting/disconnecting service as physical visit is not required.

Please also see APS's response to the following:

- AURA 1.17
- Staff 3.8
- Staff 5.50
- Staff 14.11
- Woodward 2.31



Witness: Scott Bordenkircher
Page 1 of 1

Gayer Exhibit

Gayer DR 2.23

14



INTERVENOR WARREN WOODWARD'S
SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
DECEMBER 5, 2016

Woodward 2.12: In an April 1, 2015 email, Connie Walczak, the head of ACC Consumer Services, wrote a co-worker:

What you might hear from APS is..... the meter stopped 'communicating' with the company. Seems the Smart Meters are doing this more and more often. It may be for only a brief period or a week or a month. APS seems to not have a problem with this 'non' communication, they have Schedule 8, 3.1 to rely on which enables them to estimate the bills. This can go on for months. They do not check the meter when they could retrieve the data, rather, they estimate usage. They do not feel the meter is malfunctioning if it begins communicating again. Even when it continues doing this for more than one month.

- a. Since APS began installing "smart" meters, how many APS "smart" meters have had that "non-communication" problem?
- b. For how long did that problem go on? Provide dates of when it started and when, if ever, it stopped.
- c. Is it still a problem?
- d. How many meters were replaced as a result of that problem?
- e. What were the ages of the meters that were replaced (how long in service?)?
- f. Were any of the meters under warranty?
- g. If not, who was charged the replacement cost, shareholders or ratepayers?
- h. If under warranty, did the warranty cover installation cost?
- i. If not under installation warranty, what was the installation cost and who bore the burden, shareholders or ratepayers?
- j. What brand or brands of "smart" meters had (or have) the problem?
- k. Was any of the meter "non-communication" due to externals such as vegetation? If so, was any tree trimming or other vegetative removal conducted, and what did it cost?

Response: APS disagrees with and objects to the question's premise that the need to estimate a bill due to issues with an AMI meter's ability to communicate constitutes a "problem." Currently, APS estimates less than 1% of monthly meter reads for reasons that include AMI meters not communicating with the system. However, responses to the question are provided below:

- a. Approximately 60,000 meters have been identified as having the circuit board soldering issue which is the specific

Witness: Scott Bordenkircher
Page 1 of 2

Gayer Exhibit 15

Woodward 2.12

INTERVENOR WARREN WOODWARD'S
SECOND SET OF DATA REQUESTS TO
ARIZONA PUBLIC SERVICE COMPANY REGARDING
THE APPLICATION TO APPROVE RATE SCHEDULES DESIGNED TO
DEVELOP A JUST AND REASONABLE RATE OF RETURN
DOCKET NO. E-01345A-16-0036
DECEMBER 5, 2016

Response to
Woodward
2.12
continued:

- problem referenced in the quoted e-mail.
- b. This specific communication issue was first identified in 2014 and continues to be an issue today, albeit a minimal one.
 - c. See the Company's response to subpart b.
 - d. The number of meters replaced due to this issue is as follows:
 - 2014 – 19,203 meters replaced
 - 2015 – 22,287 meters replaced
 - 2016 (As of 10/2016) – 20,172 meters replaced
 - e. The average in-service life of these meters at time of replacement was approximately 4 years.
 - f. Yes, these meters are under warranty.
 - g. See the Company's response to subpart f.
 - h. Yes, under the terms of the warranty some installation costs were covered.
 - i. Any cost of installation during the test year not covered under the warranty is necessarily included in the Company's request.
 - j. This communication issue affected Elster meters.
 - k. No. The issue is internal to the meter itself.

Spreading AZ Sun II Costs and non-AMI Meter Reading Costs

Spreading AZ Sun II Costs Over 1.2 Million Customers

Total Annual Expenditure Is Between \$10 Million and \$15 Million

Average Is \$12.5 Million

12 Months in a Year

$\$12.5 \text{ Million} / 1.2 \text{ Million Customers} = \$10.42 \text{ per year per customer}$

$\$10.42 \text{ per year per customer} = \$10.42 / 12 = 87 \text{ cents per customer per } \cancel{\text{year}} \text{ month}$

Spreading non-AMI Meter Reading Costs Over 1.2 Million Customers

Cost of Reading a Meter Is \$5.00

12 months in a Year

Number of non-AMI Meters in 16, 568

$\$5 \text{ per month} \times 12 \text{ months per year} = \$60 \text{ reading charge per year per non-AMI customer}$

$\$60 \text{ reading charge per customer per year} \times 16, 568 \text{ customer} = \$994,080 \text{ per year}$

$\$994,080 / 1.2 \text{ Million customers} = 83 \text{ cents per customer per month}$

Spreading non-AMI Meter Reading Costs Over 1.2 Million Customers

Cost of Reading a Meter Is \$15.00

12 months in a Year

Number of non-AMI Meters in 16, 568

$\$15 \text{ per month} \times 12 \text{ months per year} = \$180 \text{ reading charge per year per non-AMI customer}$

$\$180 \text{ reading charge per customer per year} \times 16, 568 \text{ customer} = \$2,982,240 \text{ per year}$

$\$2,982,240 / 1.2 \text{ Million customers} = \$2.49 \text{ per customer per month}$



Spreading AZ Sun II Costs and non-AMI Meter Reading Costs

Spreading AZ Sun II Costs Over 1.2 Million Customers

Total Annual Expenditure Is Between \$10 Million and \$15 Million

Average Is \$12.5 Million

12 Months in a Year

$\$12.5 \text{ Million} / 1.2 \text{ Million Customers} = \$10.42 \text{ per year per customer}$

$\$10.42 \text{ per year per customer} = \$10.42 / 12 = 87 \text{ cents per customer per month.}$

Spreading non-AMI Meter Reading Costs Over 1.2 Million Customers

Cost of Reading a Meter Is \$5.00

[Delete as not relevant, since \$5.00 is a compromise]

Spreading non-AMI Meter Reading Costs Over 1.2 Million Customers

Cost of Reading a Meter Is \$15.00 (APS's *actual* cost)

12 months in a Year

Number of non-AMI Meters is 16,568 (1.4% of 1.2 Million customers)

$\$15 \text{ per month} \times 12 \text{ months per year} = \$180 \text{ reading charge per year per non-AMI customer}$

$\$180 \text{ reading charge per customer per year} \times 16,568 \text{ customers} = \$2,982,240 \text{ per year}$

(Compare to \$12.5 Million per year for AZ Sun II)

$\$2,982,240 / 1.2 \text{ Million customers} = \$2.49 \text{ per customer per month}$

dividing by 12 = 20.7 cents per customer per month

Gayer Exhibit 17

